UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended September 30, 2019

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number: 001-35380

Laredo Petroleum, Inc.

(Exact name of registrant as specified in its charter)

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

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

(918) 513-4570

(Registrant's telephone number, including area code)

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**

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically, if any, every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
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. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

Number of shares of registrant's common stock outstanding as of November 4, 2019: 237,133,539

LAREDO PETROLEUM, INC.
TABLE OF CONTENTS

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements contained in or incorporated by reference into this Quarterly Report on Form 10-Q (this "Quarterly Report") are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). These forward-looking statements include statements, projections and estimates concerning our operations, performance, business strategy, oil, natural gas liquids ("NGL") and natural gas reserves, drilling program capital expenditures, liquidity and capital resources, the timing and success of specific projects, outcomes and effects of litigation, claims and disputes, derivative activities and potential financing. Forward-looking statements are generally accompanied by words such as "estimate," "project," "predict," "believe," "expect," "anticipate," "potential," "could," "may," "will," "foresee," "plan," "goal," "should," "intend," "pursue," "target," "continue," "suggest" or the negative thereof or other variations thereof or other words that convey the uncertainty of future events or outcomes. Forward-looking statements are not guarantees of performance. These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. Among the factors that significantly impact our business and could impact our business in the future are:

- the volatility of oil, NGL and natural gas prices, including in our area of operation in the Permian Basin;
- our ability to discover, estimate, develop and replace oil, NGL and natural gas reserves and inventory;
- changes in domestic and global production, supply and demand for oil, NGL and natural gas;
- revisions to our reserve estimates as a result of changes in commodity prices, decline curves and other uncertainties;
- the long-term performance of wells that were completed using different technologies;
- the ongoing instability and uncertainty in the United States and international financial and consumer markets that could adversely affect the liquidity available to us and our customers and the demand for commodities, including oil, NGL and natural gas;
- the potential impact of tighter spacing of our wells on production of oil, NGL and natural gas from our wells;
- capital requirements for our operations and projects;
- impacts of impairment write-downs on our financial statements;
- the availability and costs of drilling and production equipment, supplies, labor and oil and natural gas processing and other services;
- the availability and costs of sufficient pipeline and transportation facilities and gathering and processing capacity;
- our ability to maintain the borrowing capacity under our Fifth Amended and Restated Senior Secured Credit Facility (as amended, the "Senior Secured Credit Facility") or access other means of obtaining capital and liquidity, especially during periods of sustained low commodity prices;
- our ability to successfully identify and consummate strategic acquisitions, including the pending Acquisition (as defined below), at purchase prices that are accretive to our financial results and to successfully integrate acquired businesses, assets and properties;
- our ability to generate sufficient cash to service our indebtedness, fund our capital requirements and generate future profits;
- restrictions contained in our debt agreements, including our Senior Secured Credit Facility and the indentures governing our senior unsecured notes, as well as debt that could be incurred in the future;
- our ability to recruit and retain the qualified personnel necessary to operate our business;
- the potentially insufficient refining capacity in the United States Gulf Coast to refine all of the light sweet crude oil being produced in the United States, which could result in widening price discounts to world crude prices and potential shut-in of production due to lack of sufficient markets;
- risks related to the geographic concentration of our assets;
- our ability to hedge and regulations that affect our ability to hedge;

- changes in the regulatory environment and changes in United States or international legal, tax, political, administrative or economic conditions, including regulations that prohibit or restrict our ability to apply hydraulic fracturing to our oil and natural gas wells and to access and dispose of water used in these operations;
- legislation or regulations that prohibit or restrict our ability to drill new allocation wells;
- our ability to execute our strategies;
- competition in the oil and natural gas industry;
- drilling and operating risks, including risks related to hydraulic fracturing activities; and
- our ability to comply with federal, state and local regulatory requirements.

These forward-looking statements involve a number of risks and uncertainties that could cause actual results to differ materially from those suggested by the forward-looking statements. Forward-looking statements should, therefore, be considered in light of various factors, including those set forth under "Part I, Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations" and elsewhere in this Quarterly Report, under "Part I, Item 1A. Risk Factors" and "Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" in our Annual Report on Form 10-K for the fiscal year ended December 31, 2018 (the "2018 Annual Report") and those set forth from time to time in our other filings with the Securities and Exchange Commission (the "SEC"). These documents are available through our website or through the SEC's Electronic Data Gathering and Analysis Retrieval system at http://www.sec.gov. In light of such risks and uncertainties, we caution you not to place undue reliance on these forward-looking statements. These forward-looking statements speak only as of the date of this Quarterly Report or, if earlier, as of the date they were made. We do not intend to, and disclaim any obligation to, update or revise any forward-looking statements unless required by securities law.

Part I

Item 1. Consolidated Financial Statements (Unaudited)

Laredo Petroleum, Inc.
Consolidated balance sheets
(in thousands, except share data)
(Unaudited)

	September 30, 2019	December 31, 2018
Assets		
Current assets:		
Cash and cash equivalents	$ 31,693	$ 45,151
Accounts receivable, net	82,369	94,321
Derivatives	97,844	39,835
Other current assets	12,826	13,445
Total current assets	224,732	192,752
Property and equipment:		
Oil and natural gas properties, full cost method:		
Evaluated properties	7,186,899	6,752,631
Unevaluated properties not being depleted	65,408	130,957
Less accumulated depletion and impairment	(5,438,308)	(4,854,017)
Oil and natural gas properties, net	1,813,999	2,029,571
Midstream service assets, net	130,195	130,245
Other fixed assets, net	33,077	39,819
Property and equipment, net	1,977,271	2,199,635
Derivatives	46,605	11,030
Operating lease right-of-use assets	16,400	—
Other noncurrent assets, net	12,643	16,888
Total assets	$ 2,277,651	$ 2,420,305
Liabilities and stockholders' equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 53,608	$ 69,504
Accrued capital expenditures	24,260	29,975
Undistributed revenue and royalties	29,963	48,841
Derivatives	118	7,359
Operating lease liabilities	7,995	—
Other current liabilities	29,873	44,786
Total current liabilities	145,817	200,465
Long-term debt, net	979,972	983,636
Asset retirement obligations	56,013	53,387
Operating lease liabilities	11,420	—
Other noncurrent liabilities	5,177	8,587
Total liabilities	1,198,399	1,246,075
Commitments and contingencies		
Stockholders' equity:		
Preferred stock, $0.01 par value, 50,000,000 shares authorized and zero issued as of September 30, 2019 and December 31, 2018	—	—
Common stock, $0.01 par value, 450,000,000 shares authorized and 237,673,895 and 233,936,358 issued and outstanding as of September 30, 2019 and December 31, 2018, respectively	2,377	2,339
Additional paid-in capital	2,381,008	2,375,286
Accumulated deficit	(1,304,133)	(1,203,395)
Total stockholders' equity	1,079,252	1,174,230
Total liabilities and stockholders' equity	$ 2,277,651	$ 2,420,305

The accompanying notes are an integral part of these unaudited consolidated financial statements.

Laredo Petroleum, Inc.
Consolidated statements of operations
(in thousands, except per share data)
(Unaudited)

	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Revenues:				
Oil sales	$ 141,709	$ 160,007	$ 430,910	$ 469,972
NGL sales	20,522	50,814	74,954	115,979
Natural gas sales	7,520	15,043	21,126	45,908
Midstream service revenues	3,079	2,255	8,572	6,590
Sales of purchased oil	20,739	51,627	83,597	252,039
Total revenues	193,569	279,746	619,159	890,488
Costs and expenses:				
Lease operating expenses	22,597	23,873	68,838	68,466
Production and ad valorem taxes	11,085	14,015	29,632	38,232
Transportation and marketing expenses	5,583	5,036	15,233	6,570
Midstream service expenses	1,191	728	3,401	1,824
Costs of purchased oil	20,741	51,210	83,604	252,452
General and administrative	8,852	23,397	41,427	74,956
Restructuring expenses	5,965	—	16,371	—
Depletion, depreciation and amortization	69,099	55,963	197,900	152,278
Impairment expense	397,890	—	397,890	—
Other operating expenses	1,005	1,114	3,077	3,341
Total costs and expenses	544,008	175,336	857,373	598,119
Operating income (loss)	(350,439)	104,410	(238,214)	292,369
Non-operating income (expense):				
Gain (loss) on derivatives, net	96,684	(32,245)	136,713	(69,211)
Interest expense	(15,191)	(14,845)	(46,503)	(42,787)
Litigation settlement	—	—	42,500	—
Gain (loss) on disposal of assets, net	1,294	(616)	(315)	(4,591)
Other income (expense), net	556	(267)	4,269	629
Total non-operating income (expense), net	83,343	(47,973)	136,664	(115,960)
Income (loss) before income taxes	(267,096)	56,437	(101,550)	176,409
Income tax benefit (expense):				
Current	—	381	—	381
Deferred	2,467	(1,768)	812	(1,768)
Total income tax benefit (expense)	2,467	(1,387)	812	(1,387)
Net income (loss)	$ (264,629)	$ 55,050	$ (100,738)	$ 175,022
Net income (loss) per common share:				
Basic	$ (1.14)	$ 0.24	$ (0.44)	$ 0.75
Diluted	$ (1.14)	$ 0.24	$ (0.44)	$ 0.75
Weighted-average common shares outstanding:				
Basic	231,562	230,605	231,152	233,228
Diluted	231,562	231,639	231,152	234,207

The accompanying notes are an integral part of these unaudited consolidated financial statements.

Laredo Petroleum, Inc.
Consolidated statements of stockholders' equity
(in thousands)
(Unaudited)

	Common stock		Additional paid-in capital	Treasury stock (at cost)		Accumulated deficit	Total
	Shares	Amount		Shares	Amount		
Balance, December 31, 2018	233,936	$ 2,339	$ 2,375,286	—	$ —	$ (1,203,395)	$ 1,174,230
Restricted stock awards	5,986	60	(60)	—	—	—	—
Restricted stock forfeitures	(48)	—	—	—	—	—	—
Stock exchanged for tax withholding	—	—	—	683	(2,612)	—	(2,612)
Stock exchanged for cost of exercise of stock options	—	—	—	18	(76)	—	(76)
Retirement of treasury stock	(701)	(7)	(2,681)	(701)	2,688	—	—
Exercise of stock options	18	—	76	—	—	—	76
Stock-based compensation (See Note 6.c)	—	—	9,305	—	—	—	9,305
Net loss	—	—	—	—	—	(9,491)	(9,491)
Balance, March 31, 2019	239,191	2,392	2,381,926	—	—	(1,212,886)	1,171,432
Restricted stock awards	1,064	11	(11)	—	—	—	—
Restricted stock forfeitures	(2,763)	(28)	28	—	—	—	—
Stock exchanged for tax withholding	—	—	—	12	(34)	—	(34)
Retirement of treasury stock	(12)	—	(34)	(12)	34	—	—
Stock-based compensation (See Note 6.c)	—	—	(459)	—	—	—	(459)
Net income	—	—	—	—	—	173,382	173,382
Balance, June 30, 2019	237,480	2,375	2,381,450	—	—	(1,039,504)	1,344,321
Restricted stock awards	288	2	(2)	—	—	—	—
Restricted stock forfeitures	(93)	—	—	—	—	—	—
Stock exchanged for tax withholding	—	—	—	1	(4)	—	(4)
Retirement of treasury stock	(1)	—	(4)	(1)	4	—	—
Stock-based compensation (See Note 6.c)	—	—	(436)	—	—	—	(436)
Net loss	—	—	—	—	—	(264,629)	(264,629)
Balance, September 30, 2019	237,674	$ 2,377	$ 2,381,008	—	$ —	$ (1,304,133)	$ 1,079,252

The accompanying notes are an integral part of these unaudited consolidated financial statements.

	Common stock		Additional paid-in capital	Treasury stock (at cost)		Accumulated deficit	Total
	Shares	Amount		Shares	Amount		
Balance, December 31, 2017	242,521	$ 2,425	$ 2,432,262	—	$ —	$ (1,669,108)	$ 765,579
Adjustment to the beginning balance of accumulated deficit upon adoption of ASC 606 (see Note 13.a)	—	—	—	—	—	141,118	141,118
Restricted stock awards	3,052	30	(30)	—	—	—	—
Restricted stock forfeitures	(13)	—	—	—	—	—	—
Share repurchases	—	—	—	6,728	(58,475)	—	(58,475)
Stock exchanged for tax withholding	—	—	—	512	(4,353)	—	(4,353)
Retirement of treasury stock	(7,240)	(72)	(62,756)	(7,240)	62,828	—	—
Stock-based compensation	—	—	11,441	—	—	—	11,441
Net income	—	—	—	—	—	86,520	86,520
Balance, March 31, 2018	238,320	2,383	2,380,917	—	—	(1,441,470)	941,830
Restricted stock awards	141	2	(2)	—	—	—	—
Restricted stock forfeitures	(113)	(1)	1	—	—	—	—
Share repurchases	—	—	—	3,151	(28,743)	—	(28,743)
Stock exchanged for tax withholding	—	—	—	3	(44)	—	(44)
Retirement of treasury stock	(3,154)	(32)	(28,755)	(3,154)	28,787	—	—
Stock-based compensation	—	—	12,672	—	—	—	12,672
Net income	—	—	—	—	—	33,452	33,452
Balance, June 30, 2018	235,194	2,352	2,364,833	—	—	(1,408,018)	959,167
Restricted stock awards	55	1	(1)	—	—	—	—
Restricted stock forfeitures	(140)	(2)	2	—	—	—	—
Share repurchases	—	—	—	1,170	(9,837)	—	(9,837)
Stock exchanged for tax withholding	—	—	—	2	(14)	—	(14)
Retirement of treasury stock	(1,172)	(11)	(9,840)	(1,172)	9,851	—	—
Exercise of stock options	21	—	86	—	—	—	86
Stock-based compensation	—	—	10,660	—	—	—	10,660
Net income	—	—	—	—	—	55,050	55,050
Balance, September 30, 2018	233,958	$ 2,340	$ 2,365,740	—	$ —	$ (1,352,968)	$ 1,015,112

The accompanying notes are an integral part of these unaudited consolidated financial statements.

Laredo Petroleum, Inc.
Consolidated statements of cash flows
(in thousands)
(Unaudited)

	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Cash flows from operating activities:		
Net income (loss)	$ (100,738)	$ 175,022
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Deferred income tax (benefit) expense	(812)	1,768
Depletion, depreciation and amortization	197,900	152,278
Impairment expense	397,890	—
Non-cash stock-based compensation, net	5,244	28,748
Mark-to-market on derivatives:		
(Gain) loss on derivatives, net	(136,713)	69,211
Settlements received (paid) for matured derivatives, net	48,827	(5,943)
Settlements paid for early terminations of derivatives, net	(5,409)	—
Change in net present value of derivative deferred premiums	133	564
Premiums paid for derivatives	(7,664)	(14,930)
Amortization of debt issuance costs	2,539	2,484
Amortization of operating lease right-of-use assets	9,583	—
Other, net	2,540	9,290
Decrease (increase) in accounts receivable, net	11,778	(18,591)
Increase in other current assets	(4,088)	(6,479)
Decrease in other noncurrent assets, net	2,988	346
(Decrease) increase in accounts payable and accrued liabilities	(15,896)	28,296
(Decrease) increase in undistributed revenue and royalties	(18,878)	15,387
Decrease in other current liabilities	(21,221)	(28,298)
Decrease in other noncurrent liabilities	(1,135)	(625)
Net cash provided by operating activities	366,868	408,528
Cash flows from investing activities:		
Acquisitions of oil and natural gas properties	(2,880)	(16,340)
Capital expenditures:		
Oil and natural gas properties	(368,182)	(522,470)
Midstream service assets	(6,741)	(5,764)
Other fixed assets	(1,720)	(5,945)
Proceeds from disposition of equity method investee, net of selling costs	—	1,655
Proceeds from disposition of capital assets, net of selling costs	6,847	12,433
Net cash used in investing activities	(372,676)	(536,431)
Cash flows from financing activities:		
Borrowings on Senior Secured Credit Facility	80,000	190,000
Payments on Senior Secured Credit Facility	(85,000)	(20,000)
Share repurchases	—	(97,055)
Stock exchanged for tax withholding	(2,650)	(4,411)
Proceeds from exercise of stock options	—	86
Payments for debt issuance costs	—	(2,469)
Net cash (used in) provided by financing activities	(7,650)	66,151
Net decrease in cash and cash equivalents	(13,458)	(61,752)
Cash and cash equivalents, beginning of period	45,151	112,159
Cash and cash equivalents, end of period	$ 31,693	$ 50,407

The accompanying notes are an integral part of these unaudited consolidated financial statements.

Note 1—Organization and basis of presentation

a. *Organization*

Laredo Petroleum, Inc. ("Laredo"), together with its wholly-owned subsidiaries, Laredo Midstream Services, LLC ("LMS") and Garden City Minerals, LLC ("GCM"), is an independent energy company focused on the acquisition, exploration and development of oil and natural gas properties, and midstream and marketing services, primarily in the Permian Basin of West Texas. LMS and GCM (together, the "Guarantors") guarantee all of Laredo's debt instruments. In these notes, the "Company" refers to Laredo, LMS and GCM collectively, unless the context indicates otherwise. All amounts, dollars and percentages presented in these unaudited consolidated financial statements and the related notes are rounded and, therefore, approximate.

b. *Basis of presentation*

The unaudited consolidated financial statements were derived from the historical accounting records of the Company and reflect the historical financial position, results of operations and cash flows for the periods described herein. The unaudited consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). All material intercompany transactions and account balances have been eliminated in the consolidation of accounts.

The unaudited consolidated financial statements have not been audited by the Company's independent registered public accounting firm, except that the consolidated balance sheet as of December 31, 2018 is derived from audited consolidated financial statements. In the opinion of management, the unaudited consolidated financial statements reflect all necessary adjustments to present fairly the Company's financial position as of September 30, 2019, results of operations for the three and nine months ended September 30, 2019 and 2018 and cash flows for the nine months ended September 30, 2019 and 2018.

Certain disclosures have been condensed or omitted from the unaudited consolidated financial statements. Accordingly, the unaudited consolidated financial statements should be read in conjunction with the audited consolidated financial statements and notes thereto included in the 2018 Annual Report.

Significant accounting policies

See Note 2 in the 2018 Annual Report for discussion of significant accounting policies and Note 3 for those related to the adoption of Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 842, *Leases* ("ASC 842").

Use of estimates in the preparation of interim unaudited consolidated financial statements

The preparation of the unaudited consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions about future events. These estimates and the underlying assumptions affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Although management believes these estimates are reasonable, actual results could differ.

For further information regarding the use of estimates and assumptions, see Note 2.b in the 2018 Annual Report, Note 3 pertaining to the Company's leases and Note 6.c pertaining to the Company's 2019 performance share awards and outperformance share award.

Note 2—New accounting standards

The Company considers the applicability and impact of all accounting standard updates ("ASU") issued by the FASB and has determined there are no ASUs that are not yet adopted and meaningful to disclose as of September 30, 2019.

Accounting standard adopted

On January 1, 2019, the Company adopted ASC 842 using the modified retrospective approach and applying the optional transition method as of the beginning of the period of adoption. Results for the period beginning after January 1, 2019 are presented under ASC 842, while prior periods are not adjusted and continue to be reported under ASC 840, *Leases* ("ASC 840"). The Company utilized the transition package of expedients for leases that commenced before the effective date. ASC 842 supersedes previous lease guidance in ASC 840. The core principle of the new guidance is that a lessee should recognize on the balance sheet a liability to make lease payments and a right-of-use asset representing its right to use the underlying asset for the lease term related to its leases. For leases with a term of 12 months or less, a lessee is permitted to make an accounting policy election, by class of underlying asset, not to recognize lease assets and lease liabilities. See Note 3 for further discussion of the ASC 842 adoption impact on the Company's unaudited consolidated financial statements.

Note 3—Leases

Impact of ASC 842 adoption

Prior to January 1, 2019, the Company accounted for leases under ASC 840 and did not record any right-of-use assets or corresponding lease liabilities. Upon the adoption of ASC 842 on January 1, 2019, the Company recognized $22.1 million in operating lease right-of-use assets and $25.3 million in operating lease liabilities on the unaudited consolidated balance sheet for operating leases with a term greater than 12 months. The difference between the two balances of $3.2 million is mainly due to free rent and lease build-out incentives that were recorded as deferred lease liabilities under ASC 840. These deferred lease liabilities are subtracted from the right-of-use asset opening balance under ASC 842. The transition did not result in a material impact to the unaudited consolidated statements of operations nor was there a related impact to the unaudited consolidated statements of stockholders' equity.

The Company utilized the modified retrospective approach in adopting the new standard and applied the optional transition method as of the beginning of the period of adoption, along with the transition package of practical expedients, and implemented certain accounting policy decisions which include: (i) short-term lease recognition exemption, (ii) establishing a balance sheet recognition capitalization threshold, (iii) not evaluating existing or expired land easements that were not previously accounted for as leases under ASC 840 and (iv) accounting for certain asset classes at a portfolio level by not separating the lease and non-lease components and accounting for the agreement as a single lease component.

The Company determines whether a contract is or contains a lease at inception of the contract, based on answers to a series of questions that address whether an identified asset exists and whether the Company has the right to obtain substantially all of the benefit of the asset and to control its use over the full term of the agreement. When available, the Company uses the rate implicit in the lease to discount lease payments to present value; however, most of the Company's leases do not provide a readily determinable implicit rate. In such cases, the Company is required to use its incremental borrowing rate ("IBR"). The Company determines its IBR using both a "credit notching" approach and a "recovery method" approach. The results of these approaches are then weighted equally and averaged in order to determine the concluded IBR. This concluded IBR is utilized to discount the lease payments based on information available at lease commencement. There are no material residual value guarantees, nor any restrictions or covenants included in the Company's lease agreements.

Mineral leases, including oil and natural gas leases granting the right to explore for those natural resources and rights to use the land in which those natural resources are contained, are not included in the scope of ASC 842.

The Company has recognized operating lease right-of-use assets and operating lease liabilities on the unaudited consolidated balance sheet for leases of commercial real estate with lease terms extending into 2027 and drilling, completion, production and other equipment leases with lease terms extending through 2021. An additional drilling rig contract commenced subsequent to September 30, 2019, with a lease term extending into 2021. Accordingly, the Company will recognize an operating lease right-of-use asset and an operating lease liability on the unaudited consolidated balance sheet of $16.9 million on the drilling rig contract's commencement date. The Company has various other drilling, completion and production equipment leases on a short-term basis which are reflected in short-term lease costs.

The Company's lease costs include those that are recognized in net income (loss) during the period and capitalized as part of the cost of another asset in accordance with other GAAP.

The lease costs related to drilling, completion and production activities are reflected at the Company's net ownership, which is consistent with the principals of proportional consolidation, and lease commitments are reflected on a gross basis. As of September 30, 2019, the Company had an average working interest of 97% in Laredo-operated active productive wells in its core operating area.

Certain of the Company's leases include provisions for variable payments. These variable payments are typically determined based on a measure of throughput, actual days or another measure of usage. For our drilling rigs, the variable lease costs include the payments that depend on the performance or usage of the underlying asset, the costs to move and the costs to repair the drilling rigs. For certain of our commercial office buildings, utilities and common area, the variable lease costs are the variable maintenance charges. For our equipment leases, the variable lease costs are the amounts incurred under our contracts that are beyond the minimum rental fee, inclusive of maintenance.

The Company subleases certain office space to third parties but remains the primary obligor under the head lease. The lease terms on those subleases each contain renewal options that do not extend past the term of the head lease. The subleases do not contain residual value guarantees. Sublease income is recognized based on the contract terms and, upon the adoption of ASC 842, is included as a reduction of lease expense under the head lease.

Certain of the Company's operating lease right-of-use asset classes include options to renew on a month-to-month basis. The Company considers contract-based, asset-based, market-based, and entity-based factors to determine the term over which it is reasonably certain to extend the lease in determining its right-of-use assets and liabilities.

The Company's material leases do not include options to purchase the leased property.

The Company does not have any significant finance leases.

Lease costs

The following table presents components of total lease costs, net for the periods presented:

(in thousands)	Three months ended September 30, 2019	Nine months ended September 30, 2019
Operating lease costs(1)	$ 3,667	$ 10,908
Short-term lease costs(2)	30,966	126,400
Variable lease costs(3)	604	2,376
Sublease income	(247)	(741)
Total lease costs, net	$ 34,990	$ 138,943

(1) Amounts represent straight-line costs associated with the Company's operating lease right-of-use assets.

(2) Amounts include costs associated with the Company's short-term leases that are not included in the calculation of lease liabilities and right-of-use assets and, therefore, are not recorded on the unaudited consolidated balance sheets as such.

(3) Amounts are primarily comprised of the non-lease service component of drilling rig commitments above the minimum required payments, and are not included in the calculation of lease liabilities and right-of-use assets. Both the minimum required payments and the non-lease service component of the drilling rig commitments are capitalized as additions to oil and natural gas properties.

Operating leases

Supplemental cash flow information

The following table presents cash paid for amounts included in the measurement of operating lease liabilities, which may not agree to operating lease costs due to timing of cash payments and costs incurred for the periods presented:

(in thousands)	Three months ended September 30, 2019	Nine months ended September 30, 2019
Operating cash flows from operating leases	$ 1,467	$ 4,291
Investing cash flows from operating leases(1)	$ 2,295	$ 6,811

(1) Amounts associated with drilling operations are capitalized as additions to oil and natural gas properties.

Lease terms and discount rates

The following table presents the weighted-average remaining lease term and weighted-average discount rate for operating leases as of the date presented:

	September 30, 2019
Weighted-average remaining lease term	3.96 years
Weighted-average discount rate	8.33%

Maturities

The following table reconciles the undiscounted cash flows for recognized operating lease liabilities for each of the first five years and the total remaining years to the operating lease liabilities recorded on the unaudited consolidated balance sheet as of the date presented:

(in thousands)	September 30, 2019
Remaining 2019	$ 3,733
2020	6,808
2021	4,061
2022	2,580
2023	1,359
Thereafter	4,556
Total minimum lease payments	23,097
Less: lease liability expense	(3,682)
Present value of future minimum lease payments	19,415
Less: current operating lease liabilities	(7,995)
Noncurrent operating lease liabilities	$ 11,420

Other information

See Note 11 for disclosure of supplemental non-cash adjustments information related to operating leases. See Note 15 for disclosure of related-party lease amounts.

Disclosure for the period prior to adoption of ASC 842

As of December 31, 2018, the Company leased office space under operating leases expiring on various dates through 2027. The following table presents future minimum rental payments required as of the date presented:

(in thousands)	December 31, 2018
2019	$ 3,092
2020	3,179
2021	3,128
2022	2,560
2023	1,358
Thereafter	4,556
Total future minimum rental payments required	$ 17,873

The Company has subleased certain office space with $5.9 million of total future minimum rentals to be received as of December 31, 2018. For the period prior to the adoption of ASC 842, rent income is included in "Other income, net" on the consolidated statements of operations.

Note 4—Property and equipment

The following table presents the Company's property and equipment as of the dates presented:

(in thousands)	September 30, 2019	December 31, 2018
Evaluated oil and natural gas properties	$ 7,186,899	$ 6,752,631
Less accumulated depletion and impairment	(5,438,308)	(4,854,017)
Evaluated oil and natural gas properties, net	1,748,591	1,898,614
Unevaluated oil and natural gas properties not being depleted	65,408	130,957
Midstream service assets	179,862	172,308
Less accumulated depreciation and impairment	(49,667)	(42,063)
Midstream service assets, net	130,195	130,245
Depreciable other fixed assets	37,725	45,431
Less accumulated depreciation and amortization	(22,907)	(23,871)
Depreciable other fixed assets, net	14,818	21,560
Land	18,259	18,259
Total property and equipment, net	$ 1,977,271	$ 2,199,635

The Company uses the full cost method of accounting for its oil and natural gas properties. Under this method, all acquisition, exploration and development costs, including certain related employee costs incurred for the purpose of exploring for or developing oil and natural gas properties, are capitalized and depleted on a composite unit-of-production method based on proved oil, NGL and natural gas reserves. Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs, delay rentals and other costs related to such activities. Costs, including related employee costs, associated with production and general corporate activities are expensed in the period incurred. Sales of oil and natural gas properties, whether or not being depleted currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil, NGL and natural gas.

The following table presents costs incurred in the acquisition, exploration and development of oil and natural gas properties, with asset retirement obligations included in evaluated property acquisition costs and development costs, for the periods presented:

	Three months ended September 30,		Nine months ended September 30,	
(in thousands)	2019	2018	2019	2018
Property acquisition costs[1]:				
Evaluated	$ —	$ —	$ —	$ 13,847
Unevaluated	—	—	2,880	2,790
Exploration costs	3,480	7,502	16,101	18,747
Development costs	73,357	139,748	349,738	467,582
Total oil and natural gas properties costs incurred	$ 76,837	$ 147,250	$ 368,719	$ 502,966

(1) See Note 3.a in the third-quarter 2018 Quarterly Report for discussion of the Company's acquisitions of evaluated and unevaluated oil and natural gas properties during the nine months ended September 30, 2018.

The following table presents capitalized related employee costs incurred for the purpose of exploring for or developing oil and natural gas properties for the periods presented:

	Three months ended September 30,		Nine months ended September 30,	
(in thousands)	2019	2018	2019	2018
Capitalized related employee costs	$ 4,164	$ 5,837	$ 14,276	$ 19,101

The Company excludes the costs directly associated with the acquisition and evaluation of unevaluated properties from the depletion calculation until it is determined whether or not proved reserves can be assigned to the properties. The Company capitalizes a portion of its interest costs to its unevaluated properties. Capitalized interest becomes a part of the cost of the unevaluated properties and is subject to depletion when proved reserves can be assigned to the associated properties. All items classified as unevaluated properties are assessed on a quarterly basis for possible impairment. The assessment includes consideration of the following factors, among others: intent to drill, remaining lease term, geological and geophysical evaluations, drilling results and activity, the assignment of evaluated reserves and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to depletion.

The following table presents our depletion expense for our evaluated oil and natural gas properties per barrel of oil equivalent ("BOE") sold for the periods presented:

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	2019	2018
Depletion expense per BOE sold	$ 8.67	$ 7.94	$ 8.56	$ 7.67

The full cost ceiling is based principally on the estimated future net revenues from proved oil and natural gas properties discounted at 10%. The SEC guidelines require companies to use the unweighted arithmetic average first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period before differentials ("Benchmark Prices"). The Benchmark Prices are then adjusted for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the delivery point ("Realized Prices"). The Realized Prices are utilized to calculate the discounted future net revenues in the full cost ceiling calculation. Significant inputs included in the calculation of discounted cash flows used in the impairment analysis include the Company's estimate of operating and development costs, anticipated production of proved reserves and other relevant data. In the event the unamortized cost of evaluated oil and natural gas properties being depleted exceeds the full cost ceiling, as defined by the SEC, the excess is charged to expense in the period such excess occurs. Once incurred, a write-down of oil and natural gas properties is not reversible.

The following table presents the Benchmark Prices and the Realized Prices as of the dates presented:

	September 30, 2019	June 30, 2019	March 31, 2019	December 31, 2018	September 30, 2018
Benchmark Prices:					
Oil ($/Bbl)	$ 54.27	$ 57.90	$ 59.52	$ 62.04	$ 59.90
NGL ($/Bbl)[(1)]	$ 23.93	$ 28.21	$ 30.34	$ 31.46	$ 31.21
Natural gas ($/MMBtu)	$ 0.85	$ 1.14	$ 1.58	$ 1.76	$ 2.04
Realized Prices:					
Oil ($/Bbl)	$ 52.86	$ 55.69	$ 56.72	$ 59.29	$ 58.83
NGL ($/Bbl)	$ 14.78	$ 18.64	$ 20.46	$ 21.42	$ 21.15
Natural gas ($/Mcf)	$ 0.52	$ 0.70	$ 1.09	$ 1.38	$ 1.62

(1) Based on the Company's average composite NGL barrel.

The unamortized cost of evaluated oil and natural gas properties being depleted exceeded the full cost ceiling as of September 30, 2019. As such, there was a full cost ceiling impairment of $397.9 million for the three and nine months ended September 30, 2019, which is included in "Impairment expense" on the unaudited consolidated statements of operations. There were no full cost ceiling impairments for the nine months ended September 30, 2018. The unamortized cost of evaluated oil and natural gas properties being depleted did not exceed the full cost ceiling as of June 30, 2019, March 31, 2019, December 31, 2018 or September 30, 2018.

Note 5—Debt

a. March 2023 Notes

On March 18, 2015, the Company completed an offering of $350.0 million in aggregate principal amount of 6 1/4% senior unsecured notes due 2023 (the "March 2023 Notes"). The March 2023 Notes will mature on March 15, 2023 and bear an interest rate of 6 1/4% per annum, payable semi-annually, in cash in arrears on March 15 and September 15 of each year, commencing September 15, 2015. The March 2023 Notes are fully and unconditionally guaranteed on a senior unsecured basis by LMS, GCM and certain of the Company's future restricted subsidiaries, subject to certain automatic customary releases, including the sale, disposition or transfer of all of the capital stock or of all or substantially all of the assets of a subsidiary guarantor to one or more persons that are not the Company or a restricted subsidiary, exercise of legal defeasance or covenant defeasance options or satisfaction and discharge of the applicable indenture, designation of a subsidiary guarantor as a non-guarantor restricted subsidiary or as an unrestricted subsidiary in accordance with the applicable indenture, release from guarantee under the Senior Secured Credit Facility, or liquidation or dissolution (collectively, the "Releases"). The Company may redeem, at its option, all or part of the March 2023 Notes at any time at a price of 103.125% of face value with call premiums declining annually to 100% of face value on March 15, 2021 and thereafter plus accrued and unpaid interest to, but not including, the date of redemption.

b. January 2022 Notes

On January 23, 2014, the Company completed an offering of $450.0 million in aggregate principal amount of 5 5/8% senior unsecured notes due 2022 (the "January 2022 Notes"). The January 2022 Notes will mature on January 15, 2022 and bear an interest rate of 5 5/8% per annum, payable semi-annually, in cash in arrears on January 15 and July 15 of each year, commencing July 15, 2014. The January 2022 Notes are fully and unconditionally guaranteed on a senior unsecured basis by LMS, GCM and certain of the Company's future restricted subsidiaries, subject to certain Releases. The Company may redeem, at its option, all or part of the January 2022 Notes at any time at a price of 101.406% of face value with call premiums declining to 100% of face value on January 15, 2020 and thereafter plus accrued and unpaid interest to, but not including, the date of redemption.

c. Senior Secured Credit Facility

The Senior Secured Credit Facility matures on April 19, 2023, provided that if either the January 2022 Notes or March 2023 Notes have not been refinanced on or prior to the date (as applicable, the "Early Maturity Date") that is 90 days before their respective stated maturity dates, the Senior Secured Credit Facility will mature on such Early Maturity Date. As of September 30, 2019, the Senior Secured Credit Facility had a maximum credit amount of $2.0 billion, a borrowing base and an aggregate elected commitment of $1.1 billion each, with $185.0 million outstanding and was subject to an interest rate of 3.31%. The Senior Secured Credit Facility contains both financial and non-financial covenants, all of which the Company was in compliance with for all periods presented. Additionally, the Senior Secured Credit Facility provides for the issuance of letters of credit, limited to the lesser of total capacity or $80.0 million. As of September 30, 2019 and December 31, 2018, the Company had one letter of credit outstanding of $14.7 million under the Senior Secured Credit Facility. The Senior Secured Credit Facility is fully and unconditionally guaranteed by LMS and GCM. For additional information see Note 7.d in the 2018 Annual Report. See Note 18.a for discussion of an additional payment on the Senior Secured Credit Facility and the semi-annual borrowing base redetermination of the Senior Secured Credit Facility subsequent to September 30, 2019.

d. Long-term debt, net

The following table summarizes the net presentation of the Company's long-term debt and debt issuance costs on the unaudited consolidated balance sheets as of the dates presented:

	September 30, 2019			December 31, 2018		
(in thousands)	Long-term debt	Debt issuance costs, net	Long-term debt, net	Long-term debt	Debt issuance costs, net	Long-term debt, net
January 2022 Notes	$ 450,000	$ (2,278)	$ 447,722	$ 450,000	$ (3,010)	$ 446,990
March 2023 Notes	350,000	(2,750)	347,250	350,000	(3,354)	346,646
Senior Secured Credit Facility[(1)]	185,000	—	185,000	190,000	—	190,000
Total	$ 985,000	$ (5,028)	$ 979,972	$ 990,000	$ (6,364)	$ 983,636

(1) Debt issuance costs, net related to our Senior Secured Credit Facility of $5.7 million and $7.0 million as of September 30, 2019 and December 31, 2018, respectively, are reported in "Other noncurrent assets, net" on the unaudited consolidated balance sheets.

Note 6—Stockholders' equity and Equity Incentive Plan

a. Share repurchase program

In February 2018, the Company's board of directors authorized a $200 million share repurchase program commencing in February 2018. The repurchase program expires in February 2020. Share repurchases under the share repurchase program may be made through a variety of methods, which may include open market purchases, privately negotiated transactions and block trades. The timing and actual number of share repurchases will depend upon several factors, including market conditions, business conditions, the trading price of the Company's common stock and the nature of other investment opportunities available to the Company. During the year ended December 31, 2018, the Company repurchased 11,048,742 shares of common stock at a weighted-average price of $8.78 per common share for a total of $97.1 million under this program. All shares were retired upon repurchase. There were no share repurchases under this program during the nine months ended September 30, 2019.

b. Treasury stock

Treasury stock is recorded at cost, which includes incremental direct transaction costs, and is retired upon acquisition as a result from (i) share repurchases under the share repurchase program, (ii) stock exchanged to satisfy tax withholding that arises upon the lapse of restrictions on incentive awards at the awardee's election and (iii) stock exchanged for the cost of exercise of stock options at the awardee's election.

c. Equity Incentive Plan

The Laredo Petroleum, Inc. Omnibus Equity Incentive Plan, as amended and restated as of May 16, 2019 (the "Equity Incentive Plan"), provides for the granting of incentive awards in the form of restricted stock awards, stock option awards, performance share awards, outperformance share awards, performance unit awards and other awards. During the nine months ended September 30, 2019, the Company's stockholders approved an amendment to the Equity Incentive Plan, among other items, to increase the maximum number of shares of the Company's common stock issuable under the Equity Incentive Plan from 24,350,000 shares to 29,850,000 shares.

The Company recognizes the fair value of stock-based compensation awards, expected to vest over the requisite service period, as a charge against earnings, net of amounts capitalized. The Company's stock-based compensation awards are accounted for as equity awards and are included in "General and administrative" on the unaudited consolidated statements of operations. The Company capitalizes a portion of stock-based compensation for employees who are directly involved in the acquisition, exploration or development of oil and natural gas properties into the full cost pool. Capitalized stock-based compensation is included in "Evaluated properties" on the unaudited consolidated balance sheets. The Company's performance unit awards, granted in 2019, were accounted for as liability awards and included in "General and administrative", net of amounts capitalized, on the unaudited consolidated statements of operations for the three months ended March 31, 2019, and the corresponding liabilities were included in "Other noncurrent liabilities" on the unaudited consolidated balance sheet as of March 31, 2019. Upon their modification during the second quarter of 2019, the performance unit awards were converted to performance share awards and the performance unit award compensation was reversed. See "Performance share awards" and "Performance unit awards" below for additional discussion of the modification.

Restricted stock awards

All service vesting restricted stock awards are treated as issued and outstanding in the unaudited consolidated financial statements. Per the award agreement terms, if employment is terminated prior to the restriction lapse date for reasons other than death or disability, the restricted stock awards are forfeited and canceled and are no longer considered issued and outstanding. If the termination of employment is by reason of death or disability, all of the holder's restricted stock will automatically vest. Restricted stock awards granted to employees vest in a variety of schedules that mainly include (i) 33%, 33% and 34% vesting per year beginning on the first anniversary of the grant date and (ii) full vesting on the first anniversary of the grant date. Stock awards granted to non-employee directors vest immediately on the grant date. See Note 17 for discussion of the Company's organizational restructuring during the three and nine months ended September 30, 2019 and expected fourth-quarter 2019 forfeitures.

The following table reflects the restricted stock award activity for the nine months ended September 30, 2019:

(in thousands, except for weighted-average grant-date fair value)	Restricted stock awards	Weighted-average grant-date fair value (per award)
Outstanding as of December 31, 2018	4,196	$ 9.91
Granted	7,338	$ 3.29
Forfeited	(2,904)	$ 4.98
Vested[(1)]	(2,587)	$ 9.33
Outstanding as of September 30, 2019	6,043	$ 4.49

(1) The aggregate intrinsic value of vested restricted stock awards for the nine months ended September 30, 2019 was $9.6 million.

The Company utilizes the closing stock price on the grant date to determine the fair value of restricted stock awards. As of September 30, 2019, unrecognized stock-based compensation related to the restricted stock awards expected to vest was $16.5 million. Such cost is expected to be recognized over a weighted-average period of 2.09 years.

Stock option awards

The following table reflects the stock option award activity for the nine months ended September 30, 2019:

(in thousands, except for weighted-average exercise price and weighted-average remaining contractual term)	Stock option awards	Weighted-average exercise price (per award)	Weighted-average remaining contractual term (years)
Outstanding as of December 31, 2018	2,533	$ 12.69	5.99
Exercised[(1)]	(18)	$ 4.10	
Expired or canceled	(1,090)	$ 13.65	
Forfeited	(196)	$ 8.71	
Outstanding as of September 30, 2019	1,229	$ 12.61	5.35
Vested and exercisable as of September 30, 2019[(2)]	1,054	$ 13.26	5.10
Expected to vest as of September 30, 2019[(3)]	37	$ 9.65	6.95

(1) The exercised stock option awards for the nine months ended September 30, 2019 had de minimis intrinsic value.

(2) The vested and exercisable stock option awards as of September 30, 2019 had no aggregate intrinsic value.

(3) The expected to vest stock option awards as of September 30, 2019 had no aggregate intrinsic value.

As of September 30, 2019, unrecognized stock-based compensation related to stock option awards expected to vest was $0.2 million. Such cost is expected to be recognized over a weighted-average period of 1.07 years.

See Note 17 for discussion of the Company's organizational restructuring during the three and nine months ended September 30, 2019 and expected fourth-quarter 2019 forfeitures. See Note 8.c in the 2018 Annual Report for additional information on the stock option awards.

Performance share awards

Performance share awards, which the Company has determined are equity awards, are subject to a combination of market, performance and service vesting criteria. For performance share awards with market criteria or portions of awards with market criteria, which include: (i) the relative three-year total shareholder return comparing the Company's shareholder return to the shareholder return of the peer group specified in each award agreement ("RTSR Performance Percentage"), (ii) the Company's absolute three-year total shareholder return ("ATSR Appreciation") and (iii) the Company's total shareholder return ("TSR"), a Monte Carlo simulation prepared by an independent third party is utilized to determine the grant-date (or modification date) fair value, and the associated expense is recognized on a straight-line basis over the three-year requisite service period of the awards. For portions of awards with performance criteria, which is the Company's three-year return on average capital employed ("ROACE Percentage"), the fair value is equal to the Company's closing stock price on the grant date (or modification date), and for each reporting period, the associated expense fluctuates and is adjusted based on an estimated payout of the number of shares of common stock to be delivered on the payment date for the three-year performance period. Any shares earned under performance share awards are expected to be issued in the first quarter following the completion of the respective requisite service periods based on the achievement of certain market and performance criteria, and the payout can range from 0% to 200%. Per the award agreement terms, if employment is terminated prior to the restriction lapse date for reasons other than death or disability, the performance share awards are forfeited and canceled. If the termination of employment is by reason of death or disability, and the market and performance criteria are satisfied, then the holder of the earned performance share awards will receive a prorated number of shares based on the number of days the participant was employed with the Company during the performance period. See Note 17 for discussion of the Company's organizational restructuring during the three and nine months ended September 30, 2019 and expected fourth-quarter 2019 forfeitures.

The following table reflects the performance share award activity for the nine months ended September 30, 2019:

(in thousands, except for weighted-average grant-date fair value)	Performance share awards	Weighted-average grant-date fair value (per award)
Outstanding as of December 31, 2018	3,436	$ 13.74
Granted[1]	588	$ 2.52
Converted from performance unit awards[1][2]	1,558	$ 3.74
Forfeited	(871)	$ 12.20
Vested[3]	(1,545)	$ 17.31
Outstanding as of September 30, 2019	3,166	$ 6.28

(1) The amounts potentially payable in the Company's common stock at the end of the requisite service period for the performance share awards granted on February 28, 2019 and June 3, 2019 will be determined based on three criteria: (i) RTSR Performance Percentage, (ii) ATSR Appreciation and (iii) ROACE Percentage. The RTSR Performance Percentage, ATSR Appreciation and ROACE Percentage will be used to identify the "RTSR Factor," the "ATSR Factor" and the "ROACE Factor," respectively, which are used to compute the "Performance Multiple" and ultimately to determine the number of shares to be delivered on the payment date. In computing the Performance Multiple, the RTSR Factor is given a 25% weight, the ATSR Factor a 25% weight and the ROACE Factor a 50% weight. These awards have a performance period of January 1, 2019 to December 31, 2021.

(2) On May 16, 2019, the board of directors elected to change the form of payment from cash to common stock for the awards granted on February 28, 2019. This change in election triggered modification accounting, and the awards, formerly accounted for as liability awards, were converted to equity awards and, accordingly, new fair values were determined based on the May 16, 2019 modification date.

(3) The performance share awards granted on May 25, 2016 had a performance period of January 1, 2016 to December 31, 2018 and, as their market criteria were not satisfied, resulted in a TSR modifier of 0% based on the Company finishing in the ninth percentile of its peer group for relative TSR. As such, the granted units lapsed and were not converted into the Company's common stock during the first quarter of 2019.

The fair values per performance share award and the assumptions used to estimate these fair values per performance share award granted on February 28, 2019 and June 3, 2019 are as follows:

	February 28, 2019[1]	June 3, 2019
Market criteria (.25) RTSR Factor + (.25) ATSR Factor fair value assumptions:		
Remaining performance period	2.63 years	2.58 years
Risk-free interest rate[2]	2.14%	1.78%
Dividend yield	—%	—%
Expected volatility[3]	55.01%	55.45%
Closing stock price on May 16, 2019 and June 3, 2019 for the respective awards	$ 3.49	$ 2.59
Fair value per performance share award	$ 3.98	$ 2.45
Performance criteria (.50) ROACE Factor fair value assumption:		
Closing stock price on May 16, 2019 and June 3, 2019 for the respective awards	$ 3.49	$ 2.59
Fair value per performance share award	$ 3.49	$ 2.59
Combined fair value per performance share award[4]	$ 3.74	$ 2.52

(1) The fair values of the performance share awards granted on February 28, 2019 are based on the May 16, 2019 modification date. The total incremental compensation expense resulting from the modification of $1.0 million, which will be recognized over the life of the awards, is calculated utilizing (i) the difference between the March 31, 2019 fair value and the May 16, 2019 fair value and (ii) the outstanding quantity of the converted performance share awards as of June 30, 2019. Such expense excludes the estimated payout component for expense for the (.50) ROACE Factor as this is redetermined at each reporting period and the expense will fluctuate accordingly.

(2) The remaining performance period matched zero-coupon risk-free interest rate was derived from the U.S. Treasury constant maturities yield curve on May 16, 2019 and June 3, 2019 for the respective awards.

(3) The Company utilized its own remaining performance period matched historical volatility in order to develop the expected volatility.

(4) The combined fair value per performance share award is the combination of the fair value per performance share award weighted for the market and performance criteria for the respective awards.

The expense per performance share award, which is the fair value per performance share award adjusted for the estimated payout of the performance criteria, for the outstanding performance share awards as of September 30, 2019 and granted as of the dates presented are as follows:

	February 17, 2017	February 16, 2018	February 28, 2019	June 3, 2019
Market Criteria:				
(.25) RTSR Factor + (.25) ATSR Factor:				
Fair value per performance share award	Not applicable	$ 10.08	$ 3.98	$ 2.45
Expense per performance share award as of September 30, 2019	Not applicable	$ 10.08	$ 3.98	$ 2.45
TSR:				
Fair value per performance share award	$ 18.96	Not applicable	Not applicable	Not applicable
Expense per performance share award as of September 30, 2019	$ 18.96	Not applicable	Not applicable	Not applicable
Performance Criteria:				
(.50) ROACE Factor:				
Fair value per performance share award	Not applicable	$ 8.36	$ 3.49	$ 2.59
Estimated payout for expense as of September 30, 2019(1)	Not applicable	75%	200%	200%
Expense per performance share award as of September 30, 2019	Not applicable	$ 6.27	$ 6.98	$ 5.18
Combined expense per performance share award as of September 30, 2019(2)	$ 18.96	$ 8.18	$ 5.48	$ 3.82

(1) As the (.50) ROACE Factor is based on performance criteria, the expense fluctuates based on the estimated payout and is redetermined each reporting period and the life-to-date recognized expense for the respective awards is adjusted accordingly.

(2) The combined expense per performance share award is the combination of the expense per performance share award for market and performance criteria for the respective awards.

As of September 30, 2019, unrecognized stock-based compensation related to the performance share awards expected to vest was $8.6 million. Such cost is expected to be recognized over a weighted-average period of 2.18 years.

Outperformance share award

An outperformance share award was granted during the nine months ending September 30, 2019, in conjunction with the appointment of the Company's President, and is accounted for as an equity award. If earned, the payout ranges from 0 to 1,000,000 shares in the Company's common stock per the vesting schedule. This award is subject to a combination of market and service vesting criteria, therefore, a Monte Carlo simulation prepared by an independent third party was utilized to determine the grant-date fair value with the associated expense recognized over the requisite service period. The payout of this award is based on the highest 50 consecutive trading day average closing stock price of the Company that occurs during the performance period that commenced on June 3, 2019 and ends on June 3, 2022 ("Final Date"). Of the earned outperformance shares, one-third of the award will vest on the Final Date, one-third will vest on the first anniversary of the Final Date and one-third will vest on the second anniversary of the Final Date, provided that the participant has been continuously employed with the Company through the applicable vesting date. Per the award agreement terms, if employment is terminated prior to any vesting date for reasons other than death or disability, then any outperformance shares that have not vested as of such date shall be forfeited and canceled. If the participant's employment is terminated prior to any vesting date by reason of death or disability, and the market criteria is satisfied, then the participant will receive a prorated number of shares based on the number of days the employee was employed with the Company during the performance period.

The total fair value of the outperformance share award and the assumptions used to estimate the fair value of the outperformance share award as of the grant date presented are as follows:

		June 3, 2019
Performance period		3.00 years
Risk-free interest rate[(1)]		1.77%
Dividend yield		—%
Expected volatility[(2)]		55.77%
Closing stock price on grant date	$	2.59
Total fair value of outperformance share award (in thousands)	$	670

(1) The performance period matched zero-coupon risk-free interest rate was derived from the U.S. Treasury constant maturities yield curve on the grant date.

(2) The Company utilized its own performance period matched historical volatility in order to develop the expected volatility.

As of September 30, 2019, unrecognized stock-based compensation related to the outperformance share award expected to vest was $0.6 million. Such cost is expected to be recognized over a weighted-average period of 4.75 years.

Stock-based compensation expense

The following table reflects stock-based compensation expense for the periods presented:

	Three months ended September 30,				Nine months ended September 30,			
(in thousands)	2019		2018		2019		2018	
Restricted stock award compensation	$	2,275	$	6,001	$	10,157	$	19,332
Stock option award compensation		(300)		970		678		3,010
Performance share award compensation		(2,455)		3,689		(2,482)		12,431
Outperformance share award compensation		44		—		57		—
Total stock-based compensation, gross		(436)		10,660		8,410		34,773
Less amounts capitalized in evaluated oil and natural gas properties		(1,303)		(1,927)		(3,166)		(6,025)
Total stock-based compensation, net	$	(1,739)	$	8,733	$	5,244	$	28,748

See Note 17 for discussion of the Company's organizational restructuring and the related stock-based compensation reversals during the three and nine months ended September 30, 2019.

Performance unit awards

The performance unit awards, granted on February 28, 2019, were determined to be liability awards due to the board of directors election to settle the awards in cash. On May 16, 2019, the board of directors elected to change the form of payment from cash to common stock and, as a result, the performance unit awards were converted to performance share awards, which the Company determined were now equity awards. This change in election triggered modification accounting, and the performance unit award compensation for the three months ended March 31, 2019 was reversed and a new fair value was determined for the converted performance share awards and adjusted in stock-based compensation based on the May 16, 2019 modification date. For additional discussion of the modification, see "Performance share awards."

The following table reflects the performance unit award activity for the nine months ended September 30, 2019:

(in thousands)	Performance unit awards
Outstanding as of December 31, 2018	—
Granted	2,813
Forfeited	(1,255)
Converted to performance share awards	(1,558)
Outstanding as of September 30, 2019	—

Note 7—Derivatives

Due to the inherent volatility in oil, NGL and natural gas prices and differences in the prices of oil, NGL and natural gas between where the Company produces and where the Company sells such commodities, the Company engages in derivative transactions, such as puts, swaps, collars and basis swaps to hedge price risk associated with a portion of the Company's anticipated production. By removing a portion of the price volatility associated with future production, the Company expects to mitigate, but not eliminate, the potential effects of variability in cash flows from operations. See Notes 2.f and 9 in the 2018 Annual Report for discussion of the Company's accounting policies for derivatives and information on the transaction types and settlement indexes, respectively.

During the nine months ended September 30, 2019, the Company completed a hedge restructuring by early terminating puts and collars and entering into new swaps. The Company paid a net termination amount of $5.4 million that included the full settlement of the deferred premiums associated with these early-terminated puts and collars. The present value of these deferred premiums, classified under Level 3 of the fair value hierarchy, upon their early termination was $7.2 million. See Note 10 in the 2018 Annual Report for information about the fair value hierarchy levels.

The following table details the derivatives that were terminated:

	Aggregate volumes (Bbl)	Weighted-average floor price ($/Bbl)	Weighted-average ceiling price ($/Bbl)	Contract period
Oil puts	5,087,500	$ 46.03	$ —	April 2019 - December 2019
Oil collars	1,134,600	$ 45.00	$ 76.13	January 2020 - December 2020

The following table summarizes open derivative positions as of September 30, 2019, for derivatives that were entered into through September 30, 2019, for the settlement periods presented:

	Remaining year 2019	Year 2020	Year 2021
Oil:			
Puts:			
Volume (Bbl)	322,000	366,000	—
Weighted-average floor price ($/Bbl)	$ 55.00	$ 45.00	$ —
Volume with deferred premium (Bbl)	322,000	—	—
Weighted-average deferred premium price ($/Bbl)	$ 4.39	$ —	$ —
Swaps:			
Volume (Bbl)	1,978,000	7,173,600	—
Weighted-average price ($/Bbl)	$ 61.31	$ 59.50	$ —
Collars:			
Volume (Bbl)	—	—	912,500
Weighted-average floor price ($/Bbl)	$ —	$ —	$ 45.00
Weighted-average ceiling price ($/Bbl)	$ —	$ —	$ 71.00
Totals:			
Total volume with floor price (Bbl)	2,300,000	7,539,600	912,500
Weighted-average floor price ($/Bbl)	$ 60.42	$ 58.79	$ 45.00
Total volume with ceiling price (Bbl)	1,978,000	7,173,600	912,500
Weighted-average ceiling price ($/Bbl)	$ 61.31	$ 59.50	$ 71.00
Basis Swaps:			
WTI Midland to WTI NYMEX:			
Volume (Bbl)	920,000	—	—
Weighted-average price ($/Bbl)	$ (2.89)	$ —	$ —
WTI Midland to WTI formula basis:			
Volume (Bbl)	184,000	—	—
Weighted-average price ($/Bbl)	$ (4.05)	$ —	$ —
NGL:			
Swaps - Purity Ethane:			
Volume (Bbl)	598,000	366,000	912,500
Weighted-average price ($/Bbl)	$ 14.22	$ 13.60	$ 12.01
Swaps - Non-TET Propane:			
Volume (Bbl)	478,400	1,244,400	730,000
Weighted-average price ($/Bbl)	$ 27.97	$ 26.58	$ 25.52
Swaps - Non-TET Normal Butane:			
Volume (Bbl)	184,000	439,200	255,500
Weighted-average price ($/Bbl)	$ 30.73	$ 28.69	$ 27.72
Swaps - Non-TET Isobutane:			
Volume (Bbl)	46,000	109,800	67,525
Weighted-average price ($/Bbl)	$ 31.08	$ 29.99	$ 28.79
Swaps - Non-TET Natural Gasoline:			
Volume (Bbl)	156,400	402,600	237,250
Weighted-average price ($/Bbl)	$ 45.80	$ 45.15	$ 44.31
Total NGL volume (Bbl)	1,462,800	2,562,000	2,202,775
Natural gas:			
Henry Hub NYMEX Swaps:			
Volume (MMBtu)	9,844,000	23,790,000	14,052,500

TABLE CONTINUES ON NEXT PAGE

	Remaining year 2019	Year 2020	Year 2021
Weighted-average price ($/MMBtu)	$ 3.09	$ 2.72	$ 2.63
Basis Swaps:			
Volume (MMBtu)	9,844,000	32,574,000	23,360,000
Weighted-average price ($/MMBtu)	$ (1.51)	$ (0.76)	$ (0.47)

See Note 8.a for the fair value measurement of derivatives.

Note 8—Fair value measurements

See Note 10 in the 2018 Annual Report for discussion of the Company's accounting policies for fair value measurements.

a. Fair value measurement on a recurring basis

The following tables summarize the Company's derivatives' fair value hierarchy by commodity and current and noncurrent assets and liabilities on a gross basis and the net presentation included in "Derivatives" on the unaudited consolidated balance sheets as of the dates presented:

(in thousands)	Level 1	Level 2	Level 3	Total gross fair value	Amounts offset	Net fair value presented on the unaudited consolidated balance sheets
As of September 30, 2019:						
Assets						
Current:						
Oil derivatives	$ —	$ 57,273	$ —	$ 57,273	$ (3,248)	$ 54,025
NGL derivatives	—	22,490	—	22,490	—	22,490
Natural gas derivatives	—	30,215	—	30,215	(7,017)	23,198
Oil derivative deferred premiums	—	—	—	—	(1,869)	(1,869)
Noncurrent:						
Oil derivatives	$ —	$ 19,364	$ —	$ 19,364	$ —	$ 19,364
NGL derivatives	—	14,712	—	14,712	—	14,712
Natural gas derivatives	—	12,529	—	12,529	—	12,529
Liabilities						
Current:						
Oil derivatives	$ —	$ (4,232)	$ —	$ (4,232)	$ 3,248	$ (984)
NGL derivatives	—	—	—	—	—	—
Natural gas derivatives	—	(6,151)	—	(6,151)	7,017	866
Oil derivative deferred premiums	—	—	(1,869)	(1,869)	1,869	—
Noncurrent:						
Oil derivatives	$ —	$ —	$ —	$ —	$ —	$ —
NGL derivatives	—	—	—	—	—	—
Natural gas derivatives	—	—	—	—	—	—
Net derivative asset (liability) positions	$ —	$146,200	$ (1,869)	$144,331	$ —	$ 144,331

(in thousands)	Level 1	Level 2	Level 3	Total gross fair value	Amounts offset	Net fair value presented on the unaudited consolidated balance sheets
As of December 31, 2018:						
Assets						
Current:						
Oil derivatives	$ —	$ 44,425	$ —	$ 44,425	$ (7,907)	$ 36,518
NGL derivatives	—	1,974	—	1,974	—	1,974
Natural gas derivatives	—	18,991	—	18,991	(3,267)	15,724
Oil derivative deferred premiums	—	—	—	—	(14,381)	(14,381)
Noncurrent:						
Oil derivatives	$ —	$ 10,626	$ —	$ 10,626	$ —	$ 10,626
NGL derivatives	—	1,024	—	1,024	—	1,024
Natural gas derivatives	—	108	—	108	(728)	(620)
Liabilities						
Current:						
Oil derivatives	$ —	$ (9,059)	$ —	$ (9,059)	$ 7,907	$ (1,152)
NGL derivatives	—	—	—	—	—	—
Natural gas derivatives	—	(7,290)	—	(7,290)	3,267	(4,023)
Oil derivative deferred premiums	—	—	(16,565)	(16,565)	14,381	(2,184)
Noncurrent:						
Oil derivatives	$ —	$ —	$ —	$ —	$ —	$ —
NGL derivatives	—	—	—	—	—	—
Natural gas derivatives	—	(728)	—	(728)	728	—
Net derivative asset (liability) positions	$ —	$ 60,071	$ (16,565)	$ 43,506	$ —	$ 43,506

Significant Level 2 inputs associated with the calculation of discounted cash flows used in the fair value mark-to-market analysis of derivatives include each derivative contract's corresponding commodity index price(s), appropriate risk-adjusted discount rates and forward price curve models for substantially similar instruments generated from a compilation of data gathered from third parties.

The Company's deferred premiums associated with its derivative contracts are categorized as Level 3, as the Company utilizes a net present value calculation to determine the valuation. They are considered to be measured on a recurring basis as the derivative contracts they derive from are measured on a recurring basis. As derivative contracts containing deferred premiums are entered into, the Company discounts the associated deferred premium to its net present value at the contract trade date, using the Senior Secured Credit Facility rate at the trade date (input rate), and then records the change in net present value to interest expense over the period from trade until the final settlement date at the end of the contract. After this initial valuation, the input rate of each deferred premium is not adjusted; therefore, significant increases (decreases) in the Senior Secured Credit Facility rate would result in a significantly lower (higher) fair value measurement for each new contract entered into that contained a deferred premium; however, the initial valuation for the deferred premiums already recorded would remain unaffected. While the Company believes the sources utilized to arrive at the fair value estimates are reliable, different sources or methods could have yielded different fair value estimates. The deferred premiums are included in "Derivatives" on the unaudited consolidated balance sheets and, as of September 30, 2019, each of their input rates is 2.31%.

The following table presents payments required for derivative deferred premiums as of September 30, 2019 for the periods presented:

(in thousands)	September 30, 2019
Remaining 2019	$ 1,399
2020	477
Total	$ 1,876

The following table summarizes the changes in net assets and liabilities classified as Level 3 measurements for the periods presented:

	Three months ended September 30,		Nine months ended September 30,	
(in thousands)	2019	2018	2019	2018
Balance of Level 3 at beginning of period	$ (3,270)	$ (25,026)	$ (16,565)	$ (28,683)
Change in net present value of derivative deferred premiums[(1)]	(14)	(168)	(133)	(564)
Total purchases and settlements of derivative deferred premiums:				
Purchases	—	(2,101)	—	(7,523)
Settlements[(2)]	1,415	5,455	14,829	14,930
Balance of Level 3 at end of period	$ (1,869)	$ (21,840)	$ (1,869)	$ (21,840)

(1) These amounts are included in "Interest expense" on the unaudited consolidated statements of operations.

(2) The amount for the nine months ended September 30, 2019 includes $7.2 million that represents the present value of deferred premiums settled upon their early termination.

See Note 2.f in the 2018 Annual Report for discussion of the Company's accounting policies for derivatives.

b. Items not accounted for at fair value

The carrying amounts reported on the unaudited consolidated balance sheets for cash and cash equivalents, accounts receivable, accounts payable, accrued capital expenditures, undistributed revenue and royalties and other accrued assets and liabilities approximate their fair values.

The Company has not elected to account for its debt instruments at fair value. The following table presents the carrying amounts and fair values of the Company's debt as of the dates presented:

	September 30, 2019		December 31, 2018	
(in thousands)	Long-term debt	Fair value[(1)]	Long-term debt	Fair value[(1)]
January 2022 Notes	$ 450,000	$ 430,605	$ 450,000	$ 402,885
March 2023 Notes	350,000	311,500	350,000	316,624
Senior Secured Credit Facility	185,000	185,056	190,000	190,054
Total	$ 985,000	$ 927,161	$ 990,000	$ 909,563

(1) The fair values of the debt outstanding on the January 2022 Notes and the March 2023 Notes were determined using the September 30, 2019 and December 31, 2018 Level 1 fair value hierarchy quoted market price for each respective instrument. The fair value of the outstanding debt on the Senior Secured Credit Facility as of September 30, 2019 and December 31, 2018 was estimated utilizing the Level 2 fair value hierarchy pricing model for similar instruments. See Note 10 in the 2018 Annual Report for information about the fair value hierarchy levels.

Note 9—Net income (loss) per common share

Basic net income (loss) per common share is computed by dividing net income (loss) by the weighted-average common shares outstanding for the period. Diluted net income (loss) per common share reflects the potential dilution of non-vested restricted stock awards, outstanding stock option awards, non-vested performance share awards and the non-vested outperformance share award. See Note 6.c for additional discussion of these awards. All of these awards were anti-dilutive due to the Company's net loss and, therefore, were excluded from the calculation of diluted net income (loss) per common share for the three and nine months ended September 30, 2019. The dilutive effects of these awards were calculated utilizing the treasury stock method for the three and nine months ended September 30, 2018. See Note 10 in the third-quarter 2018 Quarterly Report for discussion of the awards excluded from the calculation of diluted net income (loss) per common share for the three and nine months ended September 30, 2018.

The following table reflects the calculations of basic and diluted (i) weighted-average common shares outstanding and (ii) net income (loss) per common share for the periods presented:

	Three months ended September 30,		Nine months ended September 30,	
(in thousands, except for per share data)	2019	2018	2019	2018
Net income (loss) (numerator):				
Net income (loss)	$ (264,629)	$ 55,050	$ (100,738)	$ 175,022
Weighted-average common shares outstanding (denominator):				
Basic[1]	231,562	230,605	231,152	233,228
Dilutive non-vested restricted stock awards	—	935	—	911
Dilutive outstanding stock option awards	—	99	—	68
Diluted	231,562	231,639	231,152	234,207
Net income (loss) per common share:				
Basic	$ (1.14)	$ 0.24	$ (0.44)	$ 0.75
Diluted	$ (1.14)	$ 0.24	$ (0.44)	$ 0.75

(1) Weighted-average common shares outstanding used in the calculation of basic and diluted net income (loss) per common share was computed taking into account share repurchases that occurred during the three and nine months ended September 30, 2018. See Note 6.a for additional discussion of the Company's share repurchase program.

See Note 17 for discussion of certain expected fourth-quarter 2019 forfeitures that did not affect diluted weighted-average common shares outstanding for the three or nine months ended September 30, 2019.

Note 10—Commitments and contingencies

a. Litigation

From time to time, the Company is subject to various legal proceedings arising in the ordinary course of business, including proceedings for which the Company may not have insurance coverage. While many of these matters involve inherent uncertainty, as of the date hereof, the Company does not currently believe that any such legal proceedings will have a material adverse effect on the Company's business, financial position, results of operations or liquidity. During the nine months ended September 30, 2019, the Company finalized and received a favorable settlement of $42.5 million in connection with the Company's damage claims asserted in a previously disclosed litigation matter relating to a breach and wrongful termination of a crude oil purchase agreement. This settlement is included in "Litigation settlement" on the unaudited consolidated statements of operations. The Company does not anticipate the receipt of further payments in connection with this matter as this settlement constituted a full and final satisfaction of the Company's claims.

b. Drilling contracts

The Company has committed to drilling rig contracts with a third party to facilitate the Company's drilling plans. One of these contracts is for a term of multiple months and contains an early termination clause that requires the Company to potentially pay penalties to the third party should the Company cease drilling efforts. These penalties would negatively impact the Company's financial statements upon early contract termination. There were no penalties incurred for early contract termination for either of the nine months ended September 30, 2019 or 2018. As the Company's current drilling rig contracts are operating leases under the scope of ASC 842, the present value of the future commitment as of September 30, 2019 related to the drilling contract with an initial term greater than 12 months is included in "Operating lease liabilities" under "Current liabilities" on the unaudited consolidated balance sheet as of September 30, 2019. See Note 3 for further discussion of the impact of the adoption of ASC 842. Management does not currently anticipate the early termination of this contract in 2019. See Note 15 for additional information regarding the drilling rig contracts as they pertain to a related party.

c. Firm sale and transportation commitments

The Company has committed to deliver, for sale or transportation, fixed volumes of product under certain contractual arrangements that specify the delivery of a fixed and determinable quantity. If not fulfilled, the Company is subject to firm transportation payments on excess pipeline capacity and other contractual penalties. These commitments are normal and customary for the Company's business. In certain instances, the Company has used spot market purchases to meet its commitments in certain locations or due to favorable pricing. Management anticipates continuing this practice in the future. No firm transportation payments on excess pipeline capacity or other contractual penalties were incurred during the three months ended September 30, 2019. The Company incurred firm transportation payments on excess pipeline capacity and other contractual penalties of $0.2 million during the three months ended September 30, 2018, and $1.0 million and $2.5 million during the nine months ended September 30, 2019 and 2018, respectively. These firm transportation payments on excess pipeline capacity and other contractual penalties are netted with the respective revenue stream on the unaudited consolidated statements of operations. Future firm sale and transportation commitments of $340.5 million as of September 30, 2019 are not recorded on the unaudited consolidated balance sheets.

d. Federal and state regulations

Oil and natural gas exploration, production and related operations are subject to extensive federal and state laws, rules and regulations. Failure to comply with these laws, rules and regulations can result in substantial penalties. The regulatory burden on the oil and natural gas industry increases the cost of doing business and affects profitability. The Company believes that it is in compliance with currently applicable federal and state regulations related to oil and natural gas exploration and production, and that compliance with the current regulations will not have a material adverse impact on the financial position or results of operations of the Company. These rules and regulations are frequently amended or reinterpreted; therefore, the Company is unable to predict the future cost or impact of complying with these regulations.

e. Environmental

The Company is subject to extensive federal, state and local environmental laws and regulations. These laws, among other things, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed in the period incurred. Liabilities for expenditures of a non-capital nature are recorded when environmental assessment or remediation is probable and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments is fixed and readily determinable. Management believes no materially significant liabilities of this nature existed as of September 30, 2019 or December 31, 2018.

Note 11—Supplemental cash flow and non-cash information

The following table presents supplemental cash flow and non-cash information:

(in thousands)	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Supplemental cash flow information:		
Capitalized interest	$ (640)	$ (710)
Net cash received (paid) for income taxes[1]	$ 691	$ (1,116)
Supplemental non-cash investing information:		
Decrease in accrued capital expenditures	$ (5,715)	$ (44,533)
Capitalized stock-based compensation in evaluated oil and natural gas properties	$ 3,166	$ 6,025
Capitalized asset retirement costs	$ 471	$ 719

(1) See Note 14 for additional discussion of the Company's income taxes.

The following table presents supplemental non-cash adjustments information related to operating leases:

(in thousands)	Nine months ended September 30, 2019
Right-of-use assets obtained in exchange for operating lease liabilities[1]	$ 25,972

(1) See Note 3 for additional discussion of the Company's leases.

Note 12—Asset retirement obligations

See Note 2.k in the 2018 Annual Report for discussion of the Company's accounting policies for asset retirement obligations.

The following table reconciles the Company's asset retirement obligation liability associated with tangible long-lived assets for the periods presented:

	Nine months ended September 30,	
(in thousands)	2019	2018
Liability at beginning of period	$ 56,882	$ 55,506
Liabilities added due to acquisitions, drilling, midstream service asset construction and other	471	719
Accretion expense	3,077	3,341
Liabilities settled due to plugging and abandonment or removed due to sale	(2,405)	(2,246)
Liability at end of period	$ 58,025	$ 57,320

Note 13—Revenue recognition

a. Impact of ASC 606 adoption on the Medallion Sale

Medallion Gathering & Processing, LLC, a Texas limited liability company formed on October 12, 2012, which, together with its wholly-owned subsidiaries (collectively, "Medallion"), was established for the purpose of developing midstream solutions and providing midstream infrastructure to bring oil to market in the Midland Basin. Prior to the Medallion Sale (defined below), LMS held 49% of Medallion's ownership units. On October 30, 2017, LMS, together with Medallion Midstream Holdings, LLC, which is owned and controlled by an affiliate of the third-party interest-holder, The Energy & Minerals Group, completed the sale of 100% of the ownership interests in Medallion to an affiliate of Global Infrastructure Partners ("GIP"), for cash consideration of $1.825 billion (the "Medallion Sale"). LMS' total net cash proceeds before taxes for its 49% ownership interest in Medallion were $831.3 million.

LMS has a Transportation Services Agreement (the "TA") with a wholly-owned subsidiary of Medallion under which LMS receives firm transportation of the Company's crude oil production from Reagan County and Glasscock County in Texas to Colorado City, Texas that continues to be in effect after the Medallion Sale. At December 31, 2017, the Medallion Sale was accounted for under the real estate guidance in ASC 360-20, *Property, Plant, and Equipment* ("ASC 360-20"), and the Company's maximum exposure to loss associated with future commitments under the TA was $141.1 million that was not recorded in the Company's unaudited consolidated balance sheets. Under ASC 360-20, as a result of the Company's continuing involvement with Medallion by guaranteeing cash flows under the TA, the Company recorded a deferred gain in the amount of its maximum exposure to loss related to such guarantees. This deferred gain would have been amortized over the TA's firm commitment transportation term through 2024 had the Company not adopted ASC 606, *Revenue from Contracts with Customers* ("ASC 606") on January 1, 2018.

In adopting ASC 606, the guidance in ASC 360-20 was superseded by ASC 860, *Transfers and Servicing* ("ASC 860"). The Medallion Sale is within the scope of ASC 860 and qualifies for sale accounting and recognition of the previously deferred gain because as of the date of the Medallion Sale (i) the Company transferred and legally isolated its full interests in Medallion to GIP, (ii) GIP received the right to pledge or exchange Medallion ownership interests at its full discretion and (iii) the Company did not have effective control over Medallion. Therefore, the deferred gain of $141.1 million was recognized as an adjustment to the 2018 beginning balance of accumulated deficit, presented on the unaudited consolidated statements of stockholders' equity, in accordance with the modified retrospective approach of adoption. See Notes 4.c and 5.a in the 2018 Annual Report for further discussion of the Medallion Sale, the TA and the adoption of ASC 606.

b. Revenue recognition

Oil, NGL and natural gas revenues are generally recognized at the point in time that control of the product is transferred to the customer. Midstream service revenues are generated through fees for products and services that need to be delivered by midstream infrastructure, including oil and liquids-rich natural gas gathering services as well as rig fuel, natural gas lift and water delivery, recycling and takeaway and are recognized over time as the customer benefits from these services when provided. A more detailed summary of the underlying contracts that give rise to the Company's revenue and method of recognition can be found in Note 5.b in the 2018 Annual Report.

Note 14—Income taxes

The Company is subject to federal and state income taxes and the Texas franchise tax. The Company had federal net operating loss carryforwards totaling $1.9 billion and state of Oklahoma net operating loss carryforwards totaling $35.8 million as of September 30, 2019, which begin expiring in 2026 and 2032, respectively. Due to the enactment of Public Law No. 115-97, a comprehensive tax reform bill commonly referred to as the Tax Cuts and Jobs Act (the "Tax Act"), $207.0 million of the federal net operating loss carryforward will not expire but may be limited in future periods. As of September 30, 2019, the Company believes it is more likely than not that a portion of the net operating loss carryforwards are not fully realizable. The Company continues to consider new evidence, both positive and negative, in determining whether, based on the weight of that evidence, a valuation allowance is needed. Such consideration includes projected future cash flows from its oil, NGL and natural gas reserves (including the timing of those cash flows), the reversal of deferred tax liabilities recorded as of September 30, 2019, the Company's ability to capitalize intangible drilling costs, rather than expensing these costs in order to prevent an operating loss carryforward from expiring unused and future projections of Oklahoma sourced income. As of September 30, 2019, a total valuation allowance of $256.8 million has been recorded to offset the Company's federal and Oklahoma net deferred tax assets, resulting in a Texas net deferred tax liability of $4.2 million, which is included in "Other noncurrent liabilities" on the unaudited consolidated balance sheets.

The Company paid Alternative Minimum Tax ("AMT") related to the Medallion Sale in 2017. The payment of AMT creates an AMT credit carryforward. Due to changes in the Tax Act, AMT credit carryforwards do not expire and are now refundable over a five-year period. Therefore, as of September 30, 2019, a receivable has been recorded in the amount of $4.1 million, of which $3.1 million is included in "Accounts receivable, net" and $1.0 million is included in "Other noncurrent assets, net" on the unaudited consolidated balance sheets.

Note 15—Related party

The Chairman of the Company's board of directors is on the board of directors of Helmerich & Payne, Inc. ("H&P"). The Company has drilling contracts with H&P that are long-term and short-term operating leases. One of the drilling contracts, which is accounted for as a long-term operating lease under the scope of ASC 842 due to its initial term of greater than 12 months, is capitalized and is included in "Operating lease right-of-use-assets" on the unaudited consolidated balance sheet. The present value of the future commitment is included in "Operating lease liabilities" under "Current liabilities" on the unaudited consolidated balance sheet. Capital expenditures for oil and natural gas properties are capitalized and are included in "Evaluated oil and natural gas properties" on the unaudited consolidated balance sheets. See Note 3 for additional discussion of the Company's adoption of ASC 842 and discussion of the drilling contract that was entered into with H&P during fourth-quarter 2019. See Note 10.b for additional discussion of the Company's drilling contracts.

The following table presents the operating lease liability related to H&P included in the unaudited consolidated balance sheet as of the date presented:

(in thousands)	September 30, 2019
Operating lease liabilities	$ 3,558

The following table presents the capital expenditures for oil and natural gas properties paid to H&P included in the unaudited consolidated statements of cash flows for the periods presented:

	Nine months ended September 30,	
(in thousands)	2019	2018
Capital expenditures for oil and natural gas properties	$ 10,828	$ —

Note 16—Subsidiary Guarantors

The Guarantors have fully and unconditionally guaranteed the January 2022 Notes, the March 2023 Notes and the Senior Secured Credit Facility, subject to the Releases. In accordance with practices accepted by the SEC, Laredo has prepared condensed consolidating financial statements to quantify the balance sheets, results of operations and cash flows of such subsidiaries as subsidiary Guarantors. The following unaudited condensed consolidating (i) balance sheets as of September 30, 2019 and December 31, 2018, (ii) statements of operations for the three and nine months ended September 30, 2019 and 2018 and (iii) statements of cash flows for the nine months ended September 30, 2019 and 2018 present financial information for Laredo on a stand-alone basis (carrying any investment in subsidiaries under the equity method), financial information for the subsidiary Guarantors on a stand-alone basis and the consolidation and elimination entries necessary to arrive at the financial information for the Company on a condensed consolidated basis. Income taxes for LMS and for GCM are recorded on Laredo's balance sheets, statements of operations and statements of cash flows as they are disregarded entities for income tax purposes. Laredo and the Guarantors are not restricted from making intercompany distributions to each other.

Condensed consolidating balance sheet
September 30, 2019

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Accounts receivable, net	$ 81,110	$ 1,259	$ —	$ 82,369
Other current assets	140,829	1,534	—	142,363
Oil and natural gas properties, net	1,831,852	9,006	(26,859)	1,813,999
Midstream service assets, net	—	130,195	—	130,195
Other fixed assets, net	33,066	11	—	33,077
Investment in subsidiaries	138,374	—	(138,374)	—
Other noncurrent assets, net	72,102	3,546	—	75,648
Total assets	$ 2,297,333	$ 145,551	$ (165,233)	$ 2,277,651
Accounts payable and accrued liabilities	$ 49,493	$ 4,115	$ —	$ 53,608
Other current liabilities	91,709	500	—	92,209
Long-term debt, net	979,972	—	—	979,972
Other noncurrent liabilities	70,048	2,562	—	72,610
Total stockholders' equity	1,106,111	138,374	(165,233)	1,079,252
Total liabilities and stockholders' equity	$ 2,297,333	$ 145,551	$ (165,233)	$ 2,277,651

Condensed consolidating balance sheet
December 31, 2018

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Accounts receivable, net	$ 83,424	$ 10,897	$ —	$ 94,321
Other current assets	97,045	1,386	—	98,431
Oil and natural gas properties, net	2,043,009	9,113	(22,551)	2,029,571
Midstream service assets, net	—	130,245	—	130,245
Other fixed assets, net	39,751	68	—	39,819
Investment in subsidiaries	128,380	—	(128,380)	—
Other noncurrent assets, net	23,783	4,135	—	27,918
Total assets	$ 2,415,392	$ 155,844	$ (150,931)	$ 2,420,305
Accounts payable and accrued liabilities	$ 54,167	$ 15,337	$ —	$ 69,504
Other current liabilities	121,297	9,664	—	130,961
Long-term debt, net	983,636	—	—	983,636
Other noncurrent liabilities	59,511	2,463	—	61,974
Total stockholders' equity	1,196,781	128,380	(150,931)	1,174,230
Total liabilities and stockholders' equity	$ 2,415,392	$ 155,844	$ (150,931)	$ 2,420,305

Condensed consolidating statement of operations
For the three months ended September 30, 2019

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Total revenues	$ 169,734	$ 34,221	$ (10,386)	$ 193,569
Total costs and expenses	521,107	32,452	(9,551)	544,008
Operating income (loss)	(351,373)	1,769	(835)	(350,439)
Interest expense	(15,191)	—	—	(15,191)
Other non-operating income, net	100,303	333	(2,102)	98,534
Income (loss) before income taxes	(266,261)	2,102	(2,937)	(267,096)
Total income tax benefit	2,467	—	—	2,467
Net income (loss)	$ (263,794)	$ 2,102	$ (2,937)	$ (264,629)

Condensed consolidating statement of operations
For the three months ended September 30, 2018

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Total revenues	$ 225,970	$ 73,463	$ (19,687)	$ 279,746
Total costs and expenses	123,942	69,146	(17,752)	175,336
Operating income	102,028	4,317	(1,935)	104,410
Interest expense	(14,845)	—	—	(14,845)
Other non-operating expense, net	(28,811)	(26)	(4,291)	(33,128)
Income before income taxes	58,372	4,291	(6,226)	56,437
Total income tax expense	(1,387)	—	—	(1,387)
Net income	$ 56,985	$ 4,291	$ (6,226)	$ 55,050

Laredo Petroleum, Inc.
Condensed notes to the consolidated financial statements
(Unaudited)

Condensed consolidating statement of operations
For the nine months ended September 30, 2019

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Total revenues	$ 527,292	$ 137,804	$ (45,937)	$ 619,159
Total costs and expenses	768,152	130,850	(41,629)	857,373
Operating income (loss)	(240,860)	6,954	(4,308)	(238,214)
Interest expense	(46,503)	—	—	(46,503)
Other non-operating income, net	190,121	718	(7,672)	183,167
Income (loss) before income taxes	(97,242)	7,672	(11,980)	(101,550)
Total income tax benefit	812	—	—	812
Net income (loss)	$ (96,430)	$ 7,672	$ (11,980)	$ (100,738)

Condensed consolidating statement of operations
For the nine months ended September 30, 2018

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Total revenues	$ 632,419	$ 312,784	$ (54,715)	$ 890,488
Total costs and expenses	345,232	302,143	(49,256)	598,119
Operating income	287,187	10,641	(5,459)	292,369
Interest expense	(42,787)	—	—	(42,787)
Other non-operating expense, net	(62,532)	(1,307)	(9,334)	(73,173)
Income before income taxes	181,868	9,334	(14,793)	176,409
Total income tax expense	(1,387)	—	—	(1,387)
Net income	$ 180,481	$ 9,334	$ (14,793)	$ 175,022

Condensed consolidating statement of cash flows
For the nine months ended September 30, 2019

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Net cash provided by operating activities	$ 370,191	$ 4,349	$ (7,672)	$ 366,868
Net cash used in investing activities	(375,999)	(4,349)	7,672	(372,676)
Net cash used in financing activities	(7,650)	—	—	(7,650)
Net decrease in cash and cash equivalents	(13,458)	—	—	(13,458)
Cash and cash equivalents, beginning of period	45,150	1	—	45,151
Cash and cash equivalents, end of period	$ 31,692	$ 1	$ —	$ 31,693

Condensed consolidating statement of cash flows
For the nine months ended September 30, 2018

(in thousands)	Laredo	Subsidiary Guarantors	Intercompany eliminations	Consolidated company
Net cash provided by operating activities	$ 402,065	$ 15,797	$ (9,334)	$ 408,528
Net cash used in investing activities	(529,968)	(15,797)	9,334	(536,431)
Net cash provided by financing activities	66,151	—	—	66,151
Net decrease in cash and cash equivalents	(61,752)	—	—	(61,752)
Cash and cash equivalents, beginning of period	112,158	1	—	112,159
Cash and cash equivalents, end of period	$ 50,406	$ 1	$ —	$ 50,407

Note 17—Organizational restructuring

On April 2, 2019, the Company announced the retirement of two of its Senior Officers. Additionally, on April 8, 2019 (the "Effective Date"), the Company committed to a company-wide reorganization effort (the "Plan") that included a workforce reduction of approximately 20%, which included an Executive Officer. The reduction in workforce was communicated to employees on the Effective Date and implemented immediately, subject to certain administrative procedures. The Company's board of directors approved the Plan in response to recent market conditions and to reduce costs and better position the Company for the future. All stock-based compensation awards held by the two Senior Officers, the Executive Officer and the employees who were affected by the Plan were forfeited and the corresponding stock-based compensation was reversed.

On September 27, 2019, in connection with the previously announced comprehensive succession planning process, the Company announced that, effective as of October 1, 2019, Randy A. Foutch would transition from his role as Chief Executive Officer. In connection with this transition and in recognition of his efforts as the Company's founder, Mr. Foutch entered into an agreement under which he received the following payments and benefits: (i) a "Founder's Bonus" of $5.9 million approved by the board of directors and (ii) 18 months of COBRA employer contributions following October 1, 2019. Accordingly, as of September 30, 2019, the forfeiture rate assumption applied to Mr. Foutch's non-vested restricted stock awards, non-vested stock option awards and non-vested performance share awards was adjusted for the expected fourth-quarter 2019 forfeiture of the respective non-vested awards.

In connection with the retirements on April 2, 2019, the Plan and the transition of Mr. Foutch, the Company incurred $6.0 million and $16.4 million of one-time charges during the three and nine months ended September 30, 2019, respectively, comprising of compensation, taxes, professional fees, outplacement and insurance-related expenses. These incurred charges were recorded as "Restructuring expenses" on the unaudited consolidated statements of operations and the corresponding liability for Mr. Foutch's transition is included in "Other current liabilities" on the unaudited consolidated balance sheets. Additionally, the total gross stock-based compensation reversal included in "General and administrative" on the unaudited consolidated statements of operations was $5.6 million and $11.7 million during the three and nine months ended September 30, 2019, respectively. See Note 6.c for additional information on the associated forfeiture activity.

Note 18—Subsequent events

a. Senior Secured Credit Facility

On October 28, 2019, the Company paid $5.0 million on the Senior Secured Credit Facility. As a result, the outstanding balance under the Senior Secured Credit Facility was $180.0 million as of November 5, 2019.

On October 30, 2019, pursuant to the semi-annual redetermination, the borrowing base and aggregate elected commitment under the Senior Secured Credit Facility were reduced to $1.0 billion each.

b. Acreage acquisition

On November 4, 2019, the Company entered into a Purchase and Sale Agreement (the "Purchase Agreement") with Cordero Energy Resources LLC ("Cordero"). Pursuant to the Purchase Agreement, the Company agreed to purchase 7,360 net acres (96% operated) and 750 net royalty acres in Howard County, Texas for $130 million, subject to customary closing purchase price adjustments and conditions (the “Acquisition”). The Acquisition will be primarily financed through borrowings under the Senior Secured Credit Facility.

Under the terms of the Purchase Agreement, the Company has deposited an amount equal to 10% of the unadjusted purchase price, or $13 million (the "Deposit"). The Purchase Agreement contains representations and warranties, covenants, termination rights and indemnification provisions that are typical for a transaction of this size and nature that provide the parties thereto with specified rights and obligations and allocate risk among them. The Company expects the Acquisition to close on or about December 12, 2019, subject to customary closing conditions. There can be no assurance that all of the conditions to closing the Acquisition will be satisfied.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our unaudited consolidated financial statements and condensed notes thereto included elsewhere in this Quarterly Report as well as our audited consolidated financial statements and notes thereto included in our 2018 Annual Report. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs and expected performance. We caution that assumptions, expectations, projections, intentions or beliefs about future events may, and often do, vary from actual results and the differences can be material. Please see "Cautionary Statement Regarding Forward-Looking Statements." Except for purposes of the unaudited consolidated financial statements and condensed notes thereto included elsewhere in this Quarterly Report, references in this Quarterly Report to "Laredo," "we," "us," "our" or similar terms refer to Laredo, LMS and GCM collectively, unless the context otherwise indicates or requires. 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 Quarterly Report are rounded and therefore approximate.

Executive overview

We are an independent energy company focused on the acquisition, exploration and development of oil and natural gas properties, and midstream and marketing services, primarily in the Permian Basin of West Texas. Since our inception, we have grown primarily through our drilling program coupled with select strategic acquisitions and joint ventures.

Our financial and operating performance for the three months ended September 30, 2019 included the following:

- Oil sales volumes of 2,560 MBbl, compared to 2,651 MBbl for the three months ended September 30, 2018, a 3% decrease over the comparative period;
- Oil, NGL and natural gas sales of $169.8 million, compared to $225.9 million for the three months ended September 30, 2018, which is the result of a 35% decrease in average sales price per BOE and was partially offset by a 15% increase in MBOE volumes sold;
- Net loss of $264.6 million, including a non-cash full cost ceiling impairment of $397.9 million, compared to net income of $55.1 million for the three months ended September 30, 2018; and
- Adjusted EBITDA (a non-GAAP financial measure) of $146.2 million, compared to $160.6 million for the three months ended September 30, 2018. See page 47 for a discussion and reconciliation of Adjusted EBITDA.

Our financial and operating performance for the nine months ended September 30, 2019 included the following:

- Oil sales volumes of 7,865 MBbl, compared to 7,604 MBbl for the nine months ended September 30, 2018, a 3% increase over the comparative period;
- Oil, NGL and natural gas sales of $527.0 million, compared to $631.9 million for the nine months ended September 30, 2018, which is the result of a 30% decrease in average sales price per BOE and was partially offset by a 19% increase in MBOE volumes sold;
- Net loss of $100.7 million, including a non-cash full cost ceiling impairment of $397.9 million, compared to net income of $175.0 million for the nine months ended September 30, 2018; and
- Adjusted EBITDA (a non-GAAP financial measure) of $422.3 million, compared to $456.5 million for the nine months ended September 30, 2018. See page 47 for a discussion and reconciliation of Adjusted EBITDA.

Recent developments

Acreage acquisition

On November 4, 2019, we entered into a purchase agreement with Cordero. Pursuant to the purchase agreement, we agreed to purchase 7,360 net acres (96% operated) and 750 net royalty acres in Howard County, Texas for $130 million, subject to customary closing purchase price adjustments and conditions. The acquisition will be primarily financed through borrowings under the Senior Secured Credit Facility.

Under the terms of the purchase agreement, we have deposited an amount equal to 10% of the unadjusted purchase price, or $13 million. The purchase agreement contains representations and warranties, covenants, termination rights and indemnification provisions that are typical for a transaction of this size and nature that provide the parties thereto with specified rights and obligations and allocate risk among them. We expect the acquisition to close on or about December 12, 2019, subject to customary closing conditions. There can be no assurance that all of the conditions to closing the acquisition will be satisfied.

Organizational restructuring

On April 2, 2019, we announced the retirement of two of our Senior Officers. Additionally, on April 8, 2019, we committed to a plan for a company-wide reorganization effort that included a workforce reduction of approximately 20%, which included an Executive Officer. Our board of directors approved the reorganization plan in response to market conditions and to reduce costs and better position us for the future. Also, in connection with the previously announced comprehensive succession planning process, effective as of October 1, 2019, Randy A. Foutch, Chairman of our board of directors, transitioned from his role as Chief Executive Officer. In connection with the retirements on April 2, 2019, the reorganization plan and the transition of Mr. Foutch, we incurred $6.0 million and $16.4 million of one-time charges during the three and nine months ended September 30, 2019, respectively. See Note 17 to our unaudited consolidated financial statements included elsewhere in this Quarterly Report for discussion of the organizational restructuring.

Core area of operations

The oil and liquids-rich Permian Basin is characterized by multiple target horizons, long-lived reserves, high drilling success rates and high initial production rates. As of September 30, 2019, we had assembled 122,398 net acres in the Permian Basin.

Pricing and reserves

Our results of operations are heavily influenced by oil, NGL and natural gas prices. Oil, NGL and natural gas price fluctuations are caused by changes in global and regional supply and demand, market uncertainty, economic conditions, transportation constraints and a variety of additional factors. Historically, commodity prices have experienced significant fluctuations, and additional changes in commodity prices may affect the economic viability of, and our ability to fund, our drilling projects, as well as the economic valuation and economic recovery of oil, NGL and natural gas reserves.

We have entered into a number of derivative contracts that have enabled us to offset a portion of the changes in our cash flow caused by fluctuations in price and basis differentials for our sales of oil, NGL and natural gas, as discussed in "Item 3. Quantitative and Qualitative Disclosures About Market Risk."

Our reserves as of September 30, 2019 and December 31, 2018 are reported in three streams: oil, NGL and natural gas. The Realized Prices utilized to value our proved reserves as of September 30, 2019 and September 30, 2018, were $52.86 per Bbl for oil, $14.78 per Bbl for NGL and $0.52 per Mcf for natural gas, and $58.83 per Bbl for oil, $21.15 per Bbl for NGL and $1.62 per Mcf for natural gas, respectively. The Realized Prices used to estimate proved reserves do not include derivative transactions. The unamortized cost of our evaluated oil and natural gas properties exceeded the full cost ceiling as of September 30, 2019 and, as such, we recorded a third-quarter non-cash full cost ceiling impairment of $397.9 million. No such impairments were recorded during the nine months ended September 30, 2018. See Note 4 to our unaudited consolidated financial statements included elsewhere in this Quarterly Report for discussion of our full cost method of accounting.

Horizontal drilling of unconventional wells using enhanced completions techniques, including, but not limited to, hydraulic fracturing, is a relatively new process and, as such, forecasting the long-term production of such wells is inherently uncertain and subject to varying interpretations. As we receive and process geological and production data from these wells over time, we analyze such data to confirm whether previous assumptions regarding original forecasted production, inventory and reserves continue to appear accurate or require modification. While all production forecasts have elements of uncertainty over the life of the related wells, we are seeing indications that the oil portion of such reserves may be less than originally anticipated and the decline curves may be steeper than originally anticipated.

Initial production results, production decline rates, well density, completion design and operating method are examples of the numerous uncertainties and variables inherent in the estimation of proved reserves in future periods. The quantity of proved reserves is one of the many variables inherent in the calculation of depletion.

The following table presents our depletion expense for our evaluated oil and natural gas properties per BOE sold for the periods presented:

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	2019	2018
Depletion expense per BOE sold	$ 8.67	$ 7.94	$ 8.56	$ 7.67

Low commodity price impact on our third-quarter and potentially on our fourth-quarter 2019 full cost ceiling impairment test

Our results of operations are heavily influenced by oil, NGL and natural gas prices, which remain at low levels. Oil, NGL and natural gas price fluctuations are caused by changes in global and regional supply and demand, market uncertainty, economic conditions and a variety of additional factors. Since the inception of our oil and natural gas activities, commodity prices have experienced significant fluctuations, and additional changes in commodity prices may affect the economic viability of, and our ability to fund, our drilling projects, as well as the economic valuation and economic recovery of oil, NGL and natural gas reserves.

We use the full cost method of accounting for our oil and natural gas properties, with the full cost ceiling based principally on the estimated future net revenues from our proved oil and natural gas properties discounted at 10% under required SEC guidelines for pricing methodology. In the event the unamortized cost of evaluated oil and natural gas properties being depleted exceeds the full cost ceiling, as defined by the SEC, the excess is charged to expense in the period such excess occurs. Once incurred, a write-down of oil and natural gas properties is not reversible.

The net book value of our evaluated oil and natural gas properties exceeded the full cost ceiling as of September 30, 2019. As such, we recorded a third-quarter 2019 non-cash full cost ceiling impairment of $397.9 million. We did not record any similar impairments for the years ended December 31, 2018 or 2017, but did record non-cash full cost ceiling impairments of $161.1 million and $2.4 billion for the years ended December 31, 2016 and 2015, respectively.

If prices remain at or below the current levels, subject to numerous factors and inherent limitations, some of which are discussed below, and all other factors remain constant, we will incur an additional non-cash full cost ceiling impairment in the fourth quarter of 2019, which will have an adverse effect on our results of operations.

There are numerous uncertainties inherent in the estimation of proved reserves and accounting for oil and natural gas properties in future periods. In addition to unknown future commodity prices, other uncertainties include (i) changes in drilling and completions costs, (ii) changes in oilfield service costs, (iii) production results, (iv) our ability, in a low price environment, to strategically drill the most economic locations in our multi-level horizontal targets, (v) income tax impacts, (vi) potential recognition of additional proved undeveloped reserves, (vii) any potential value added to our proved reserves when testing recoverability from drilling unbooked locations, (viii) revisions to production curves based on additional data and (ix) the inherent significant volatility in the commodity prices for oil, NGL and natural gas.

Each of the above factors is evaluated on a quarterly basis and if there is a material change in any factor it is incorporated into our reserves estimation utilized in our quarterly accounting estimates. We use our reserve estimates to evaluate, also on a quarterly basis, the reasonableness of our resource development plans for our reported proved reserves. Changes in circumstance, including commodity pricing, economic factors and the other uncertainties described above may lead to changes in our development plans.

Set forth below is a calculation of a potential future impairment of our evaluated oil and natural gas properties. Such implied impairment should not be interpreted to be indicative of our development plan or of our actual future results. Each of the uncertainties noted above has been evaluated for material known trends to be potentially included in the estimation of possible fourth-quarter effects. Based on such review, we determined that the impact of decreased commodity prices is the only significant known variable necessary in calculating the following scenario.

Our hypothetical fourth-quarter 2019 full cost ceiling calculation has been prepared by substituting (i) $51.08 per Bbl for oil, (ii) $12.10 per Bbl for NGL and (iii) $0.57 per Mcf for natural gas (collectively, the "Pro Forma Fourth-Quarter Prices") for the respective Realized Prices as of September 30, 2019. All other inputs and assumptions have been held constant. Accordingly, this estimation strictly isolates the estimated impact of low commodity prices on the fourth-quarter 2019 Realized Prices that will be utilized in our full cost ceiling calculation. The Pro Forma Fourth-Quarter Prices use a slightly modified Realized Price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for oil, NGL and natural gas for the 10 months ended October 1, 2019 and holding the October 30, 2019 prices constant for the remaining eleventh and twelfth months of the calculation. Based solely on the substitution of the Pro Forma Fourth-Quarter Prices into our September 30, 2019 proved reserve estimates, the implied fourth-quarter impairment would be $170 million. We believe that substituting these prices into our September 30, 2019 proved reserve estimates may help provide users with an understanding of the potential impact on our fourth-quarter 2019 full cost ceiling test.

We have entered into a number of derivatives, which have enabled us to offset a portion of the changes in our cash flow caused by price fluctuations in our sales of oil, NGL and natural gas as discussed in “Item 3. Quantitative and Qualitative Disclosures About Market Risk.”

See Note 4 to our unaudited consolidated financial statements included elsewhere in this Quarterly Report for prices used to value our reserves and additional discussion of our full cost impairment. See "Part II, Item 1A. Risk Factors—Risks related to our business—As a result of the volatility in prices for oil, NGL and natural gas, we have taken and may be required to take further write-downs of the carrying values of our properties" included elsewhere in this Quarterly Report.

Results of operations

Revenues

Sources of our revenue

Our revenues are derived from the sale of produced oil, NGL and natural gas, the sale of purchased oil and providing midstream services to third parties, all within the continental United States and do not include the effects of derivatives. Our oil, NGL and natural gas revenues may vary significantly from period to period as a result of changes in volumes of production, pricing differentials and/or changes in commodity prices. Our sales of purchased oil revenue may vary due to changes in oil prices, pricing differentials and the amount of volumes purchased. Our midstream service revenues may vary due to oil throughput fees and the level of services provided to third parties for (i) oil and natural gas gathering and transportation systems and related facilities, (ii) natural gas lift, rig fuel and centralized compression infrastructure and (iii) water storage, recycling and transportation infrastructure. See Notes 2.n and 5.b to our consolidated financial statements in our 2018 Annual Report for additional information regarding our revenue recognition policies.

The following table presents our sources of revenue as a percentage of total revenues:

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	2019	2018
Oil sales	73%	57%	70%	53%
NGL sales	11%	18%	12%	13%
Natural gas sales	4%	5%	3%	5%
Midstream service revenues	1%	1%	1%	1%
Sales of purchased oil	11%	19%	14%	28%
Total	100%	100%	100%	100%

Oil, NGL and natural gas sales volumes, revenues and prices

The following table presents information regarding our oil, NGL and natural gas sales volumes, sales revenues and average sales prices:

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	2019	2018
Sales volumes:				
Oil (MBbl)	2,560	2,651	7,865	7,604
NGL (MBbl)	2,344	1,987	6,643	5,328
Natural gas (MMcf)	15,790	11,577	43,731	32,697
Oil equivalents (MBOE)(1)(2)	7,537	6,567	21,797	18,381
Average daily oil equivalent sales volumes (BOE/D)(2)	81,921	71,382	79,843	67,330
Average daily oil sales volumes (Bbl/D)(2)	27,830	28,812	28,810	27,854
Sales revenues (in thousands):				
Oil	$ 141,709	$ 160,007	$ 430,910	$ 469,972
NGL	20,522	50,814	74,954	115,979
Natural gas	7,520	15,043	21,126	45,908
Total oil, NGL and natural gas sales revenues	$ 169,751	$ 225,864	$ 526,990	$ 631,859
Average sales prices(2):				
Oil, without derivatives ($/Bbl)(3)	$ 55.35	$ 60.36	$ 54.79	$ 61.80
NGL, without derivatives ($/Bbl)(3)	$ 8.75	$ 25.57	$ 11.28	$ 21.77
Natural gas, without derivatives ($/Mcf)(3)	$ 0.48	$ 1.30	$ 0.48	$ 1.40
Average sales price, without derivatives ($/BOE)(3)	$ 22.52	$ 34.39	$ 24.18	$ 34.38
Oil, with derivatives ($/Bbl)(4)	$ 56.15	$ 55.41	$ 53.59	$ 57.50
NGL, with derivatives ($/Bbl)(4)	$ 13.43	$ 23.99	$ 13.83	$ 20.95
Natural gas, with derivatives ($/Mcf)(4)	$ 1.01	$ 1.79	$ 1.09	$ 1.79
Average sales price, with derivatives ($/BOE)(4)	$ 25.38	$ 32.78	$ 25.75	$ 33.04

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

The following table presents settlements received (paid) for matured derivatives and premiums paid previously or upon settlement attributable to derivatives that matured during the periods utilized in our calculation of the average sales prices, with derivatives presented above:

	Three months ended September 30,		Nine months ended September 30,	
(in thousands)	2019	2018	2019	2018
Settlements received (paid) for matured derivatives:				
Oil	$ 5,813	$ (7,279)	$ 5,199	$ (16,623)
NGL	10,964	(3,154)	16,905	(4,348)
Natural gas	8,468	6,545	26,723	15,028
Total	$ 25,245	$ (3,888)	$ 48,827	$ (5,943)
Premiums paid previously or upon settlement attributable to derivatives that matured during the respective period:				
Oil	$ (3,748)	$ (5,849)	$ (14,589)	$ (16,090)
Natural gas	—	(850)	—	(2,536)
Total	$ (3,748)	$ (6,699)	$ (14,589)	$ (18,626)

Changes in average sales prices and sales volumes caused the following changes to our oil, NGL and natural gas revenues between the three months ended September 30, 2019 and 2018:

(in thousands)	Oil	NGL	Natural gas	Total net effect of change
2018 Revenues	$ 160,007	$ 50,814	$ 15,043	$ 225,864
Effect of changes in average sales prices	(12,846)	(39,436)	(12,999)	(65,281)
Effect of changes in sales volumes	(5,452)	9,144	5,476	9,168
2019 Revenues	$ 141,709	$ 20,522	$ 7,520	$ 169,751

Changes in average sales prices and sales volumes caused the following changes to our oil, NGL and natural gas revenues between the nine months ended September 30, 2019 and 2018:

(in thousands)	Oil	NGL	Natural gas	Total net effect of change
2018 Revenues	$ 469,972	$ 115,979	$ 45,908	$ 631,859
Effect of changes in average sales prices	(55,194)	(69,673)	(40,276)	(165,143)
Effect of changes in sales volumes	16,132	28,648	15,494	60,274
2019 Revenues	$ 430,910	$ 74,954	$ 21,126	$ 526,990

Oil sales revenue. Our oil sales revenue is a function of oil sales volumes and average oil sales prices received for those volumes. The decrease in oil sales revenue of $18.3 million, or 11%, for the three months ended September 30, 2019, compared to the same period in 2018 is due to an 8% decrease in average oil sales prices and a 3% decrease in oil sales volumes.

The decrease in oil sales revenue of $39.1 million, or 8%, for the nine months ended September 30, 2019, compared to the same period in 2018 is due to an 11% decrease in average oil sales prices and was partially offset by a 3% increase in oil sales volumes.

NGL sales revenue. Our NGL sales revenue is a function of NGL sales volumes and average NGL sales prices received for those volumes. The decrease in NGL sales revenue of $30.3 million, or 60%, for the three months ended September 30, 2019, compared to the same period in 2018 is due to a 66% decrease in average NGL sales prices and was partially offset by an 18% increase in NGL sales volumes.

The decrease in NGL sales revenue of $41.0 million, or 35%, for the nine months ended September 30, 2019, compared to the same period in 2018 is due to a 48% decrease in average NGL sales prices and was partially offset by a 25% increase in NGL sales volumes.

Natural gas sales revenue. Our natural gas sales revenue is a function of natural gas sales volumes and average natural gas sales prices received for those volumes. The decrease in natural gas sales revenue of $7.5 million, or 50%, for the three months ended September 30, 2019, compared to the same period in 2018 is due to a 63% decrease in average natural gas sales prices and was partially offset by a 36% increase in natural gas sales volumes.

The decrease in natural gas sales revenue of $24.8 million, or 54%, for the nine months ended September 30, 2019, compared to the same period in 2018 is due to a 66% decrease in average natural gas sales prices and was partially offset by a 34% increase in natural gas sales volumes.

The following table presents midstream service and sales of purchased oil revenues:

	Three months ended September 30,		Nine months ended September 30,	
(in thousands)	**2019**	**2018**	**2019**	**2018**
Midstream service revenues	$ 3,079	$ 2,255	$ 8,572	$ 6,590
Sales of purchased oil	$ 20,739	$ 51,627	$ 83,597	$ 252,039

Midstream service revenues. Our midstream service revenues increased by $0.8 million, or 37%, and by $2.0 million, or 30%, for the three and nine months ended September 30, 2019, respectively, compared to the same periods in 2018 mainly due to an increase in water service revenues, which corresponds to a similar increase in water service costs included in midstream service expenses during the same periods. These revenues fluctuate and will vary due to oil throughput fees and the level of services provided to third parties.

Sales of purchased oil. These revenues are a function of the volumes and prices of purchased oil sold to customers and are offset by the volumes and costs of purchased oil. Sales of purchased oil decreased by $30.9 million, or 60%, and by $168.4 million, or 67%, for the three and nine months ended September 30, 2019, respectively, compared to the same periods in 2018 mainly due to decreases in the volumes of purchased oil sold of 50% and 63% for the three and nine months ended September 30, 2019, respectively, compared to the same periods in 2018.

We enter into purchase transactions with third parties and separate sale transactions. These transactions are presented on a gross basis as we act as the principal in the transaction by assuming control of the commodities purchased and the responsibility to deliver the commodities sold. Revenue is recognized when control transfers to the purchaser/customer at the delivery point based on the price received. The transportation costs associated with these transactions are presented as a component of costs of purchased oil. See "—Costs and expenses - Costs of purchased oil."

Costs and expenses

The following table presents information regarding costs and expenses and average selected costs and expenses per BOE sold:

(in thousands except for per BOE sold data)	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Costs and expenses:				
Lease operating expenses	$ 22,597	$ 23,873	$ 68,838	$ 68,466
Production and ad valorem taxes	11,085	14,015	29,632	38,232
Transportation and marketing expenses	5,583	5,036	15,233	6,570
Midstream service expenses	1,191	728	3,401	1,824
Costs of purchased oil	20,741	51,210	83,604	252,452
General and administrative:				
Cash	10,591	14,664	36,183	46,208
Non-cash stock-based compensation, net[1]	(1,739)	8,733	5,244	28,748
Restructuring expenses	5,965	—	16,371	—
Depletion, depreciation and amortization	69,099	55,963	197,900	152,278
Impairment expense	397,890	—	397,890	—
Other operating expenses	1,005	1,114	3,077	3,341
Total costs and expenses	$ 544,008	$ 175,336	$ 857,373	$ 598,119
Average selected costs and expenses per BOE sold[2]:				
Lease operating expenses	$ 3.00	$ 3.63	$ 3.16	$ 3.72
Production and ad valorem taxes	1.47	2.13	1.36	2.08
Transportation and marketing expenses	0.74	0.77	0.70	0.36
Midstream service expenses	0.16	0.11	0.16	0.10
General and administrative:				
Cash	1.41	2.23	1.66	2.51
Non-cash stock-based compensation, net[1]	(0.23)	1.33	0.24	1.56
Depletion, depreciation and amortization	9.17	8.52	9.08	8.28
Total selected costs and expenses	$ 15.72	$ 18.72	$ 16.36	$ 18.61

(1) For the three and nine months ended September 30, 2019, non-cash stock-based compensation, net, excluding forfeitures related to our organizational restructuring, was $3.9 million and $16.4 million, respectively, and on a per BOE sold basis was $0.52 and $0.75, respectively.

(2) Average selected costs and expenses per BOE sold are based on actual amounts and are not calculated using the rounded numbers presented in the table above.

Lease operating expenses ("LOE"). LOE, which includes workover expenses, decreased by $1.3 million, or 5%, and increased by $0.4 million, or 1%, for the three and nine months ended September 30, 2019, respectively, compared to the same periods in 2018. On a per BOE sold basis, LOE decreased by 17% and 15% for the three and nine months ended September 30, 2019, respectively, compared to the same periods in 2018. We continue to focus on economic efficiencies associated with the usage and procurement of products and services related to LOE.

Production and ad valorem taxes. Production and ad valorem taxes decreased by $2.9 million, or 21%, and by $8.6 million, or 22%, for the three and nine months ended September 30, 2019, respectively, compared to the same periods in 2018. The year-to-date decrease is partially attributed to a $4.5 million production tax refund, related to additional marketing costs claimed for fiscal years 2013 through 2016, recorded during the first quarter of 2019. Production taxes, which are established by federal, state or local taxing authorities, are based on and fluctuate in proportion to our oil, NGL and natural gas sales revenues. Ad valorem taxes are based on and fluctuate in proportion to the taxable value assessed by the various counties where our oil and natural gas properties are located.

Transportation and marketing expenses. Transportation and marketing expenses increased by $0.5 million, or 11%, and by $8.7 million, or 132%, for the three and nine months ended September 30, 2019, respectively, compared to the same periods in 2018. In July 2018, we began recognizing transportation and marketing expenses incurred for the delivery of produced oil to a customer in the U.S. Gulf Coast market. We expect these expenses to increase as we are a contracted firm shipper on the Gray Oak Pipeline, which is expected to be in service by the end of 2019.

Midstream service expenses. Midstream service expenses increased by $0.5 million, or 64%, and by $1.6 million, or 86%, for the three and nine months ended September 30, 2019, respectively, compared to the same periods in 2018 mainly due to an increase in water service costs, which corresponds to a similar increase in water service revenue included in midstream service revenues during the same periods. Midstream service expenses are costs incurred to operate and maintain our (i) oil and natural gas gathering and transportation systems and related facilities, (ii) centralized oil storage tanks, (iii) natural gas lift, rig fuel and centralized compression infrastructure and (iv) water storage, recycling and transportation facilities.

Costs of purchased oil. Costs of purchased oil decreased by $30.5 million, or 59%, and by $168.8 million, or 67%, for the three and nine months ended September 30, 2019, respectively, compared to the same periods in 2018 mainly due to decreases in the volumes of purchased oil of 50% and 63% for the three and nine months ended September 30, 2019, respectively, compared to the same periods in 2018. These are costs incurred for obtaining oil from third parties and, in some cases, transporting such oil utilized in our marketing activities.

General and administrative ("G&A"). Total G&A decreased by $14.5 million, or 62%, and by $33.5 million, or 45%, for the three and nine months ended September 30, 2019, respectively, compared to the same periods in 2018 mainly due to decreases in stock-based compensation, net and decreases in cash G&A as a result of our measures taken to align our cost structure with operational activity. Stock-based compensation, net, decreased by $10.5 million, or 120%, and by $23.5 million, or 82%, for the three and nine months ended September 30, 2019, respectively, compared to the same periods in 2018 mainly due to the expected forfeiture related to the fourth-quarter transition of Randy A. Foutch from his role as Chief Executive Officer and our second-quarter organizational restructuring. All stock-based compensation awards held by Mr. Foutch and by officers and employees who were affected by the organizational restructuring were recorded as reversals to stock-based compensation, net of $5.6 million and $11.2 million during the three and nine months ended September 30, 2019, respectively. See Note 6.c to our unaudited consolidated financial statements included elsewhere in this Quarterly Report for information regarding our stock-based compensation.

Restructuring expenses. Organizational restructuring expenses relate to (i) the retirement of two of our Senior Officers, (ii) the Plan, which included a workforce reduction, implemented in response to recent market conditions and to reduce costs and better position ourselves for the future and (iii) our announcement, in connection with the previously announced comprehensive succession planning process, that, effective as of October 1, 2019, Randy A. Foutch would transition from his role as Chief Executive Officer. We incurred $6.0 million and $16.4 million of one-time charges during the three and nine months ended September 30, 2019, respectively, comprising of compensation, taxes, professional fees, outplacement and insurance-related expenses. As of September 30, 2019, no additional restructuring expenses are expected to be incurred. See Note 17 to our unaudited consolidated financial statements included elsewhere in this Quarterly Report for further discussion of the organizational restructuring.

Depletion, depreciation and amortization ("DD&A"). The following table presents the components of DD&A:

	Three months ended September 30,		Nine months ended September 30,	
(in thousands)	**2019**	**2018**	**2019**	**2018**
Depletion of evaluated oil and natural gas properties	$ 65,354	$ 52,169	$ 186,662	$ 140,971
Depreciation of midstream service assets	2,575	2,456	7,619	7,321
Depreciation and amortization of other fixed assets	1,170	1,338	3,619	3,986
Total DD&A	$ 69,099	$ 55,963	$ 197,900	$ 152,278

DD&A increased by $13.1 million, or 23%, and by $45.6 million, or 30%, for the three and nine months ended September 30, 2019, respectively, compared to the same periods in 2018. These increases are mainly due to (i) the previous reduction in our December 31, 2018 proved reserve volume, (ii) an increase in the depletion base and (iii) an increase in production volumes sold. Depletion expense per BOE increased 9% and 12% for the three and nine months ended September 30, 2019, respectively, compared to the same periods in 2018. For further discussion of our depletion expense per BOE see Note 4 to our unaudited consolidated financial statements included elsewhere in this Quarterly Report and "—Pricing and reserves."

Impairment expense. Our net book value of evaluated oil and natural gas properties exceeded the full cost ceiling as of September 30, 2019, and, as a result, we recorded a full cost ceiling impairment of $397.9 million for the three and nine months ended September 30, 2019. There were no full cost ceiling impairments for the nine months ended September 30, 2018. Impairment of our oil and natural gas properties is based principally on the estimated future net revenues from proved oil and natural gas properties discounted at 10%. The Realized Prices are utilized to calculate the discounted future net revenues in the full cost ceiling calculation. In the event the unamortized cost of evaluated oil and natural gas properties being depleted exceeds the full cost ceiling, as defined by the SEC, the excess is charged to expense in the period such excess occurs. Once incurred, a write-down of oil and natural gas properties is not reversible. With the continuing volatility in commodity prices, we may incur additional write-downs on our oil and natural gas properties. See Note 4 to our unaudited consolidated financial statements included elsewhere in this Quarterly Report and "—Recent developments" for additional information regarding our full cost ceiling calculation.

Non-operating income (expense)

The following table presents the components of non-operating income (expense), net:

	Three months ended September 30,		Nine months ended September 30,	
(in thousands)	**2019**	**2018**	**2019**	**2018**
Gain (loss) on derivatives, net	$ 96,684	$ (32,245)	$ 136,713	$ (69,211)
Interest expense	(15,191)	(14,845)	(46,503)	(42,787)
Litigation settlement	—	—	42,500	—
Gain (loss) on disposal of assets, net	1,294	(616)	(315)	(4,591)
Other income (expense), net	556	(267)	4,269	629
Total non-operating income (expense), net	$ 83,343	$ (47,973)	$ 136,664	$ (115,960)

Gain (loss) on derivatives, net. The following table presents the changes in the components of gain (loss) on derivatives, net:

(in thousands)	**Three months ended September 30, 2019 compared to 2018**	**Nine months ended September 30, 2019 compared to 2018**
Change in non-cash gain (loss) on derivatives, net	$ 95,756	$ 149,297
Change in settlements received (paid) for matured derivatives, net	29,133	54,770
Change in settlements paid for early terminations of derivatives, net	—	(5,409)
Change in premiums paid for derivatives	4,040	7,266
Total change in gain (loss) on derivatives, net	$ 128,929	$ 205,924

The change in non-cash gain (loss) on derivatives is the result of new, matured and early-terminated contracts and the changing relationship between our outstanding contract prices and the future market prices in the forward curves, which we use to calculate the fair value of our derivatives. In general, if outstanding contracts are held constant, we experience gains during periods of decreasing market prices and losses during periods of increasing market prices. Settlements received or paid for matured derivatives are based on the settlement prices of our matured derivatives compared to the prices specified in the derivative contracts. During the nine months ended September 30, 2019, we recognized significant non-cash gains in the net fair value of our derivatives outstanding due to decreases in the applicable futures curves that we have hedged, bolstered by our hedge restructuring that increased our weighted-average oil floor prices for 2019 and 2020.

During the nine months ended September 30, 2019, we completed a hedge restructuring by early terminating puts and collars and entering into new swaps. We paid a net termination amount of $5.4 million that included the full settlement of the deferred premiums associated with these early-terminated puts and collars. The present value of these deferred premiums, classified under Level 3 of the fair value hierarchy, upon their early termination was $7.2 million.

See Notes 7 and 8.a to our unaudited consolidated financial statements included elsewhere in this Quarterly Report and "Item 3. Quantitative and Qualitative Disclosures About Market Risk" for additional information regarding our derivatives.

Interest expense. Interest expense increased by $0.3 million, or 2%, and by $3.7 million, or 9%, for the three and nine months ended September 30, 2019, respectively, compared to the same periods in 2018 mainly due to increases in the amount outstanding on our Senior Secured Credit Facility.

Litigation settlement. During the nine months ended September 30, 2019, we finalized and received a favorable settlement of $42.5 million in connection with our damage claims asserted in a previously disclosed litigation matter relating to a breach and wrongful termination of a crude oil purchase agreement. We do not anticipate the receipt of further payments in connection with this matter as this settlement constituted a full and final satisfaction of our claims.

Gain (loss) on disposal of assets, net. The change in gain (loss) on disposal of assets, net was $1.9 million and $4.3 million for the three and nine months ended September 30, 2019, respectively, compared to the same periods in 2018. From time to time, we dispose of inventory, midstream service assets and other fixed assets. The associated gain or loss recorded during the period fluctuates depending upon the volume of the assets disposed, their associated net book value and, in the case of a disposal by sale, the sale price.

Income tax benefit (expense)

Income tax benefit for the three and nine months ended September 30, 2019 was $2.5 million and $0.8 million, respectively. We are subject to federal and state income taxes and the Texas franchise tax. As of September 30, 2019, we determined it was more likely than not that our federal and Oklahoma net deferred tax assets were not realizable through future net income. As of September 30, 2019, a total valuation allowance of $256.8 million has been recorded to offset our federal and Oklahoma net deferred tax assets, resulting in a Texas net deferred tax liability of $4.2 million. During the three months ended September 30, 2019, we updated our effective tax rate to 0.8% from the 1.0% used during the first half of 2019, as fourth-quarter 2019 events have become more estimable. As such, the effective tax rate for our operations was 0.8% for the nine months ended September 30, 2019. For further discussion of our valuation allowance, see Note 14 to our unaudited consolidated financial statements included elsewhere in this Quarterly Report.

Liquidity and capital resources

Historically, our primary sources of liquidity have been cash flows from operations, proceeds from equity offerings, proceeds from senior unsecured note offerings, borrowings under our Senior Secured Credit Facility and proceeds from asset dispositions. We believe cash flows from operations and availability under our Senior Secured Credit Facility provide sufficient liquidity to manage our cash needs and contractual obligations and to fund our expected capital expenditures. Our primary operational uses of capital have been for the acquisition, exploration and development of oil and natural gas properties and infrastructure development.

A significant portion of our capital expenditures can be adjusted and managed by us. We continually monitor the capital markets and our capital structure and consider which financing alternatives, including equity and debt capital resources, joint ventures and asset sales, are available to meet our future planned or accelerated capital expenditures. We may make changes to our capital structure from time to time, with the goal of maintaining financial flexibility, preserving or improving liquidity and/or achieving cost efficiency. Such financing alternatives, including capital market transactions and debt and equity repurchases, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material. For further discussion of our financing activities included elsewhere in this Quarterly Report, see: (i) Note 5 for our debt instruments and (ii) Note 6.a and "Part II. Item 2. Purchases of Equity Securities" below for our $200.0 million share repurchase program authorized by our board of directors and commenced in February 2018. We also continuously look for other opportunities to maximize shareholder value.

Due to the inherent volatility in oil, NGL and natural gas prices and differences in the prices of oil, NGL and natural gas between where we produce and where we sell such commodities, we engage in derivative transactions, such as puts, swaps, collars and basis swaps to hedge price risk associated with a portion of our anticipated production. By removing a portion of the price volatility associated with future production, we expect to mitigate, but not eliminate, the potential effects of variability in cash flows from operations. See "Part I. Item 3. Quantitative and Qualitative Disclosures About Market Risk" below.

See Note 7 to our unaudited consolidated financial statements included elsewhere in this Quarterly Report for discussion of our hedge restructuring during the nine months ended September 30, 2019 and corresponding summary of open derivative positions as of September 30, 2019 for derivatives that were entered into through September 30, 2019.

We continually seek to maintain a financial profile that provides operational flexibility. As of September 30, 2019, we had cash and cash equivalents of $31.7 million and available capacity under the Senior Secured Credit Facility, after the reduction for outstanding letters of credit, of $900.3 million, resulting in total liquidity of $932.0 million. As of November 4, 2019, we had cash and cash equivalents of $18.0 million and available capacity under the Senior Secured Credit Facility, after the reduction for outstanding letters of credit, of $805.3 million, resulting in total liquidity of $823.3 million. We believe that our operating cash flows and the aforementioned liquidity sources provide us with the financial resources to manage our business needs, to implement our planned capital expenditure budget and, at our discretion, to fund our share repurchase program, pay down or refinance debt or increase our planned capital expenditure budget. In addition, the pending Acquisition is expected to be primarily financed through borrowing under the Senior Secured Credit Facility. 2019 has been a transitional year as we have tailored our operational cadence and corporate cost structure, including G&A expense, to target a balance between capital expenditures and cash flows from operations. We have also aligned our personnel costs with activity levels with a reduction in force. We have restructured our oil hedges, securing additional cash flow to increase activity and substantially accelerating the time frame in which we began to generate free cash flow while also growing oil production.

Cash flows

The following table presents our cash flows:

(in thousands)	Nine months ended September 30, 2019	2018
Net cash provided by operating activities	$ 366,868	$ 408,528
Net cash used in investing activities	(372,676)	(536,431)
Net cash (used in) provided by financing activities	(7,650)	66,151
Net decrease in cash and cash equivalents	$ (13,458)	$ (61,752)

Cash flows from operating activities

Net cash provided by operating activities decreased by $41.7 million, or 10%, for the nine months ended September 30, 2019, compared to the same period in 2018. Notable cash changes include (i) a decrease in oil, NGL and natural gas sales revenues, (ii) a decrease of $38.6 million from net working capital changes, (iii) an increase of $56.6 million in settlements received for matured and early terminations of derivatives, net of premiums paid and (iv) receipt of $42.5 million for the litigation settlement. The decrease in oil, NGL and natural gas sales revenues is due to the decrease in average sales prices without derivatives for oil, NGL and natural gas, partially offset by increased sales volumes of all production streams. See "—Results of operations" for additional discussion of changes in our oil, NGL and natural gas sales revenues.

Our operating cash flows are sensitive to a number of variables, the most significant of which are the volatility of oil, NGL and natural gas prices, mitigated to the extent of our derivatives' exposure, and sales volume levels. Regional and worldwide economic activity, weather, infrastructure, transportation capacity to reach markets, costs of operations, legislation and regulations and other variable factors significantly impact the prices of these commodities. These factors are not within our control and are difficult to predict. For additional information on risks related to our business, see "Part I. Item 1A. Risk Factors" in our 2018 Annual Report.

Cash flows from investing activities

Net cash used in investing activities decreased by $163.8 million, or 31%, for the nine months ended September 30, 2019, compared to the same period in 2018, mainly due to decreases in our capital expenditure budget and acquisitions of oil and natural gas properties, partially offset by a decrease in proceeds from disposition of capital assets, net of selling costs. Additionally, accrued capital expenditures decreased significantly during the nine months ended September 30, 2018.

The following table presents the components of our cash flows from investing activities:

(in thousands)	Nine months ended September 30, 2019	2018
Acquisitions of oil and natural gas properties	$ (2,880)	$ (16,340)
Capital expenditures:		
Oil and natural gas properties	(368,182)	(522,470)
Midstream service assets	(6,741)	(5,764)
Other fixed assets	(1,720)	(5,945)
Proceeds from disposition of equity method investee, net of selling costs	—	1,655
Proceeds from disposition of capital assets, net of selling costs	6,847	12,433
Net cash used in investing activities	$ (372,676)	$ (536,431)

Cash flows from financing activities

Net cash (used in) provided by financing activities decreased by $73.8 million, or 112%, for the nine months ended September 30, 2019, compared to the same period in 2018, and is mainly attributable to decreased borrowings and increased payments on our Senior Secured Credit Facility and 2018 share repurchases under our share repurchase program. During the year ended December 31, 2018, we repurchased 11,048,742 shares of common stock at a weighted-average price of $8.78 per common share for a total of $97.1 million under this program. All shares were retired upon repurchase. There were no share repurchases under this program during the nine months ended September 30, 2019. As of September 30, 2019, we had authorization remaining to repurchase until expiration of the program in February 2020, $102.9 million of common stock.

For further discussion of our financing activities included elsewhere in this Quarterly Report, see: (i) Note 5 for our debt instruments and (ii) Note 6.a and "Part II. Item 2. Purchases of Equity Securities" below for our $200.0 million share repurchase program authorized by our board of directors and commenced in February 2018.

The following table presents the components of our cash flows from financing activities:

(in thousands)	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Borrowings on Senior Secured Credit Facility	$ 80,000	$ 190,000
Payments on Senior Secured Credit Facility	(85,000)	(20,000)
Share repurchases	—	(97,055)
Stock exchanged for tax withholding	(2,650)	(4,411)
Proceeds from exercise of stock options	—	86
Payments for debt issuance costs	—	(2,469)
Net cash (used in) provided by financing activities	$ (7,650)	$ 66,151

Capital expenditure budget

Our goal is to achieve cash flow neutrality at a minimum and, therefore, our capital spending in 2019 and 2020 will ultimately be influenced by commodity price changes and, among other factors, changes in service costs and drilling and completions efficiencies. Due to improving drilling and completions efficiencies, we adjusted our expected capital expenditures, excluding non-budgeted acquisitions, during the third quarter of 2019 to $490.0 million for calendar year 2019, which is an increase of $25.0 million from the previously announced level. We do not have a specific acquisition budget since the timing and size of acquisitions cannot be accurately forecasted.

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

(in thousands)	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Oil and natural gas properties[(1)]	$ 76,837	$ 147,250	$ 365,839	$ 486,329
Midstream service assets	1,147	383	7,584	3,649
Other fixed assets	999	1,255	1,966	6,197
Total costs incurred, excluding non-budgeted acquisition costs	$ 78,983	$ 148,888	$ 375,389	$ 496,175

(1) See Note 4 included elsewhere in this Quarterly Report for additional information regarding our costs incurred in the exploration and development of oil and natural gas properties.

The amount, timing and allocation of capital expenditures are largely discretionary and within management's control. If oil, NGL and natural gas prices decline below our acceptable levels, or costs increase above our acceptable levels, we may choose to defer a portion of our budgeted capital expenditures until later periods to achieve the desired balance between sources and uses of liquidity and prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flow. Subject to financing alternatives, we may also increase our capital expenditures significantly to take advantage of opportunities we consider to be attractive. We consistently monitor and may adjust our projected capital expenditures in response to success or lack of success in drilling activities, changes in prices, availability of financing and joint venture opportunities, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs and supplies, changes in service costs, contractual obligations, internally generated cash flow and other factors both within and outside our control.

Debt

As of September 30, 2019, we were a party only to our Senior Secured Credit Facility and the indentures governing our senior unsecured notes.

Senior Secured Credit Facility

The Senior Secured Credit Facility matures on April 19, 2023, provided that if either the January 2022 Notes or March 2023 Notes have not been refinanced on or prior to the date (as applicable, the "Early Maturity Date") that is 90 days before their respective stated maturity dates, the Senior Secured Credit Facility will mature on such Early Maturity Date. As of September 30, 2019, the Senior Secured Credit Facility had a maximum credit amount of $2.0 billion, a borrowing base and an aggregate elected commitment of $1.1 billion each, with $185.0 million outstanding and was subject to an interest rate of 3.31%. The Senior Secured Credit Facility contains both financial and non-financial covenants, all of which we were in compliance with for all periods presented. Additionally, the Senior Secured Credit Facility provides for the issuance of letters of credit, limited to the lesser of total capacity or $80.0 million. As of September 30, 2019 and December 31, 2018, we had one letter of credit outstanding of $14.7 million under the Senior Secured Credit Facility. The Senior Secured Credit Facility is fully and unconditionally guaranteed by LMS and GCM.

On October 30, 2019, pursuant to the semi-annual redetermination, the borrowing base and aggregate elected commitment under our Senior Secured Credit Facility were reduced to $1.0 billion each.

Senior unsecured notes

The following table presents principal amounts and applicable interest rates for our outstanding senior unsecured notes as of September 30, 2019:

(in millions, except for interest rates)	Principal	Interest rate
January 2022 Notes	$ 450.0	5.625%
March 2023 Notes	350.0	6.250%
Total senior unsecured notes	$ 800.0	

See Notes 5.a and 5.b to our unaudited consolidated financial statements included elsewhere in this Quarterly Report for further discussion of the March 2023 Notes and January 2022 Notes, respectively.

Obligations and commitments

The following table presents significant contractual obligations and commitments as of September 30, 2019 and December 31, 2018 and their associated changes:

($ in thousands, except % change)	September 30, 2019	December 31, 2018	$ change	% change
Senior Unsecured Notes[(1)]	$ 939,844	$ 987,031	$ (47,187)	(5)%
Firm sale and transportation commitments[(2)]	340,545	365,940	(25,395)	(7)%
Senior Secured Credit Facility[(3)]	185,000	190,000	(5,000)	(3)%
Asset retirement obligations[(4)]	58,025	56,882	1,143	2 %
Lease commitments[(5)]	23,097	34,374	(11,277)	(33)%
Derivative deferred premiums[(6)]	1,876	16,797	(14,921)	(89)%
Sand purchase and supply agreement[(7)]	—	3,858	(3,858)	(100)%
Total	$ 1,548,387	$ 1,654,882	$ (106,495)	(6)%

(1) Values presented include both our principal and interest obligations. The decrease in such balance as of September 30, 2019 is due to our semi-annual interest payments made in January, March, July and September of 2019. See Notes 5.a and 5.b to our unaudited consolidated financial statements included elsewhere in this Quarterly Report for additional discussion of our March 2023 Notes and January 2022 Notes, respectively.

(2) We have committed to deliver, for sale or transportation, fixed volumes of product under certain contractual arrangements that specify the delivery of a fixed and determinable quantity. If not fulfilled, we are subject to firm transportation payments on excess pipeline capacity and other contractual penalties. The decrease in such commitments as of September 30, 2019 is mainly due to our fulfillment of contractual commitments, partially offset by new sale commitments and changes to existing transportation commitments. See Note 10.c to our unaudited consolidated financial statements included elsewhere in this Quarterly Report for additional discussion of our firm sale and transportation commitments.

(3) This table does not include future loan advances, repayments, commitment fees or other fees on our Senior Secured Credit Facility as we cannot determine with accuracy the timing of such items. Additionally, this table does not include interest expense as it is a floating rate instrument and we cannot determine with accuracy the future interest rates to be charged. The decrease in such balance as of September 30, 2019 is due to our payments, partially offset by our borrowings. As of September 30, 2019, the principal on our Senior Secured Credit Facility is due on April 19, 2023.

(4) Amounts represent our asset retirement obligation liabilities. See Note 12 to our unaudited consolidated financial statements included elsewhere in this Quarterly Report for additional discussion of our asset retirement obligations.

(5) Amounts represent our minimum lease payments. See Notes 2 and 3 to our unaudited consolidated financial statements included elsewhere in this Quarterly Report for discussion of our adoption of ASC 842 on January 1, 2019. For simplicity, we have combined our drilling contracts into the "Lease Commitments" line item for 2019 presentation purposes. The decrease in lease commitments as of September 30, 2019 is mainly due to the settlements paid for our fulfillment of lease commitments, partially offset by new lease commitments. We have committed to drilling rig contracts with a third party to facilitate our drilling plans. Included in the value in the table is the gross amount we are committed to pay for our drilling contracts, however, we will record our proportionate share based on our working interest in our consolidated financial statements as incurred. See Note 10.b to our unaudited consolidated financial statements included elsewhere in this Quarterly Report for additional discussion of our drilling contracts.

(6) Amounts represent payments required for derivative deferred premiums on our commodity hedging contracts. The decrease in premiums as of September 30, 2019 is mainly due to premiums paid for derivatives and settlements paid for early terminations of derivatives. See Note 8.a to our unaudited consolidated financial statements included elsewhere in this Quarterly Report for additional discussion of our deferred premiums.

(7) At September 30, 2019, we had met our commitment to purchase sand under this purchase and supply agreement.

Non-GAAP financial measures

The non-GAAP financial measures of Free Cash Flow and Adjusted EBITDA, as defined by us, may not be comparable to similarly titled measures used by other companies. Therefore, these non-GAAP 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 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

Free Cash Flow does not represent funds available for future discretionary use because those funds are 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 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 September 30,		Nine months ended September 30,	
(in thousands)	**2019**	**2018**	**2019**	**2018**
Net cash provided by operating activities	$ 105,599	$ 145,927	$ 366,868	$ 408,528
Less:				
Increase in current assets and liabilities, net	(21,183)	(313)	(48,305)	(9,685)
(Increase) decrease in noncurrent assets and liabilities, net	(1,124)	(1,570)	1,853	(279)
Cash flows from operating activities before changes in assets and liabilities, net	127,906	147,810	413,320	418,492
Less costs incurred, excluding non-budgeted acquisition costs:				
Oil and natural gas properties	76,837	147,250	365,839	486,329
Midstream service assets	1,147	383	7,584	3,649
Other fixed assets	999	1,255	1,966	6,197
Total costs incurred, excluding non-budgeted acquisition costs	78,983	148,888	375,389	496,175
Free Cash Flow	$ 48,923	$ (1,078)	$ 37,931	$ (77,683)

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 September 30,		Nine months ended September 30,	
(in thousands)	**2019**	**2018**	**2019**	**2018**
Net income (loss)	$ (264,629)	$ 55,050	$ (100,738)	$ 175,022
Plus:				
Income tax (benefit) expense	(2,467)	1,387	(812)	1,387
Depletion, depreciation and amortization	69,099	55,963	197,900	152,278
Impairment expense	397,890	—	397,890	—
Non-cash stock-based compensation, net	(1,739)	8,733	5,244	28,748
Restructuring expenses	5,965	—	16,371	—
Accretion expense	1,005	1,114	3,077	3,341
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	(96,684)	32,245	(136,713)	69,211
Settlements received (paid) for matured derivatives, net	25,245	(3,888)	48,827	(5,943)
Settlements paid for early terminations of derivatives, net	—	—	(5,409)	—
Premiums paid for derivatives	(1,415)	(5,455)	(7,664)	(14,930)
Interest expense	15,191	14,845	46,503	42,787
Litigation settlement	—	—	(42,500)	—
(Gain) loss on disposal of assets, net	(1,294)	616	315	4,591
Adjusted EBITDA	$ 146,167	$ 160,610	$ 422,291	$ 456,492

Critical accounting policies and estimates

The discussion and analysis of our financial condition and results of operations are based upon our unaudited consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our unaudited consolidated financial statements.

There have been no material changes in our critical accounting policies and procedures during the nine months ended September 30, 2019. See our critical accounting policies in "Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" of the 2018 Annual Report. Furthermore, see Note 3 to our unaudited consolidated financial statements included elsewhere in this Quarterly Report for discussion of the impact of the adoption of ASC 842.

New accounting standards

For discussion of new accounting standards, see Note 2 to our unaudited consolidated financial statements included elsewhere in this Quarterly Report. See Note 3 to our unaudited consolidated financial statements included elsewhere in this Quarterly Report for discussion related to the adoption of ASC 842.

Off-balance sheet arrangements

Currently, we do not have any off-balance sheet arrangements other than our firm sale and transportation commitments, which are described in "—Obligations and commitments." In addition, we have certain operating leases with a term less than or equal to 12 months that we have made an accounting policy election to not record on the unaudited consolidated balance sheets. See

Notes 3 and 10 to our unaudited consolidated financial statements included elsewhere in this Quarterly Report for additional information on our leases and commitments and contingencies, respectively.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risk. The term "market risk," in our case, refers to the risk of loss arising from adverse changes in oil, NGL and natural gas prices and in interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of how we view and manage our ongoing market risk exposures. All of our market risk-sensitive derivative instruments were entered into for hedging purposes, rather than for speculative trading.

Commodity price exposure

Due to the inherent volatility in oil, NGL and natural gas prices and differences in the prices of oil, NGL and natural gas between where we produce and where we sell such commodities, we engage in derivative transactions, such as puts, swaps, collars and basis swaps to hedge price risk associated with a portion of our anticipated production. By removing a portion of the price volatility associated with future production, we expect to mitigate, but not eliminate, the potential effects of variability in cash flows from operations.

During a significant portion of 2018, Midland market crude oil prices experienced an increased discount to WTI Cushing and WTI Houston prices. These discounts have narrowed in 2019, however, they remain volatile. During a significant portion of 2018 and in 2019, the West Texas WAHA market natural gas prices experienced an increased discount to Henry Hub NYMEX prices and continues to remain volatile. The discounts are primarily due to limited pipeline capacity constraining transportation of crude oil and natural gas out of the Permian Basin to major market hubs including, but not limited to, Cushing, Oklahoma and the United States Gulf Coast. These pipeline constraints may continue to affect Midland market crude oil prices and West Texas WAHA market natural gas prices until further transportation capacity becomes operational or until basin-wide crude oil and natural gas production decreases from its current levels. We expect the basin differential to narrow, as new pipeline capacity is expected to become operational during the remaining portion of 2019 and the first half of 2020. We are a contracted firm shipper on the Gray Oak Pipeline, which is expected to be in service by the end of 2019. We will continue to pursue avenues to attempt to protect our oil and natural gas value from basin differentials by securing crude oil transportation capacity, which enables us to sell oil in multiple markets, and entering into basis-swap derivatives, which provides pricing protection.

The fair values of our open derivative contracts are largely determined by forward price curves of the relevant indexes. As of September 30, 2019, a 10% change in the forward curves associated with our derivatives would have changed our unaudited consolidated balance sheet's net derivative position to the following amounts:

(in thousands)	10% Increase	10% Decrease
Net asset derivative position	$ 78,579	$ 211,308

As of September 30, 2019 and December 31, 2018, the net derivative positions were assets of $144.3 million and $43.5 million, respectively. See Notes 7 and 8.a to our unaudited consolidated financial statements included elsewhere in this Quarterly Report for additional disclosures regarding our derivatives.

Interest rate risk

Our Senior Secured Credit Facility bears interest at a floating rate and our January 2022 Notes and March 2023 Notes bear interest at fixed rates. The maturity years, outstanding balances and interest rates on our long-term debt as of September 30, 2019 were as follows:

	Maturity year	
(in millions except for interest rates)	2022	2023(1)
Senior Secured Credit Facility	$ —	$ 185.0
Floating interest rate	—%	3.313%
January 2022 Notes	$ 450.0	$ —
Fixed interest rate	5.625%	—%
March 2023 Notes	$ —	$ 350.0
Fixed interest rate	—%	6.250%

(1) The Senior Secured Credit Facility matures on April 19, 2023, provided that if either the January 2022 Notes or March 2023 Notes have not been refinanced on or prior to the applicable Early Maturity Date, the Senior Secured Credit Facility will mature on such Early Maturity Date.

Counterparty and customer credit risk

See Note 13 in the 2018 Annual Report for additional disclosures regarding credit risk. See Note 2.e in the 2018 Annual Report for additional disclosures regarding our accounts receivable. See Note 13 to our unaudited consolidated financial statements included elsewhere in this Quarterly Report for additional information regarding revenue recognition. See Notes 7 and 8.a to our unaudited consolidated financial statements included elsewhere in this Quarterly Report for additional disclosures regarding our derivatives.

Item 4. Controls and Procedures

Evaluation of disclosure controls and procedures

As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of Laredo's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act), was performed under the supervision and with the participation of Laredo's management, including our principal executive officer and principal financial officer. Based on that evaluation, these officers concluded that Laredo's disclosure controls and procedures were effective as of September 30, 2019. Our disclosure controls and other procedures are designed to provide reasonable assurance that the information required to be disclosed in the reports we file and submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to Laredo's management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

Evaluation of changes in internal control over financial reporting

There were no changes in our internal control over financial reporting during the quarter ended September 30, 2019 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Part II

Item 1. Legal Proceedings

From time to time, we are subject to various legal proceedings arising in the ordinary course of business, including proceedings for which we may not have insurance coverage. While many of these matters involve inherent uncertainty as of the date hereof, we do not currently believe that any such legal proceedings will have a material adverse effect on our business, financial position, results of operations or liquidity.

Item 1A. Risk Factors

In addition to the other information set forth in this Quarterly Report, you should carefully consider the risks discussed in our 2018 Annual Report. Other than the risk factor set forth below, there have been no material changes in our risk factors from those described in the 2018 Annual Report. The risks described in such reports are not the only risks facing us. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition or future results.

As a result of the volatility in prices for oil, NGL and natural gas, we have taken and may be required to take further write-downs of the carrying value of our evaluated oil and natural gas properties.

Accounting rules require that we periodically review the carrying value of our evaluated oil and natural gas properties for possible impairment. Based on prevailing commodity prices and specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we have been required to, and may be required to further write down the carrying value of our evaluated oil and natural gas properties. A write-down constitutes a non-cash charge to earnings.

Our unamortized cost of evaluated oil and natural gas properties being depleted exceeded the full cost ceiling as of September 30, 2019 and as a result, we recorded a non-cash full cost ceiling impairment of $397.9 million for the three and nine months ended September 30, 2019. We did not record any similar impairments for the years ended December 31, 2018 or 2017, but did record non-cash full cost ceiling impairments of $161.1 million and $2.4 billion for the years ended December 31, 2016 and 2015, respectively. If prices remain at or below the current levels, subject to numerous factors and inherent limitations, and all other factors remain constant, we will incur an additional non-cash full cost ceiling impairment in the fourth quarter of 2019, which will have an adverse effect on our results of operations. See "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations—Recent developments" and Note 4 to our unaudited consolidated financial statements included elsewhere in this Quarterly Report for discussion of our full cost method of accounting.

We may be unable to consummate the Acquisition and, if we do, the Acquisition may not achieve its intended results.

The Purchase Agreement for the pending Acquisition for approximately $130 million contains customary closing conditions and is subject to customary purchase price adjustments. It is possible that one or more of the conditions in the Purchase Agreement will not be satisfied, and we may be unable or unwilling to consummate the Acquisition. The Purchase Agreement provides that upon the termination of the Purchase Agreement by the seller, under certain circumstances, the seller may be entitled to retain the $13 million deposit as liquidated damages. Furthermore, a large portion of the acreage we are acquiring is undeveloped, and our plans, development schedule and production schedule associated with the acreage may fail to materialize. As a result, our investment in these areas may not be as economic as we anticipate, and we could incur material write-downs of unevaluated properties.

Item 2. Purchases of Equity Securities

The following table summarizes purchases of common stock by Laredo:

Period	Total number of shares purchased	Weighted-average price paid per share	Total number of shares purchased as part of publicly announced plans	Maximum value that may yet be purchased under the program as of the respective period-end date[1]
July 1, 2019 - July 31, 2019	—	$ —	—	$ 102,945,283
August 1, 2019 - August 31, 2019	—	$ —	—	$ 102,945,283
September 1, 2019 - September 30, 2019	—	$ —	—	$ 102,945,283
Total	—		—	

(1) In February 2018, our board of directors authorized a $200 million share repurchase program commencing in February 2018. The repurchase program expires in February 2020. Share repurchases under the share repurchase program may be made through a variety of methods, which may include open market purchases, privately negotiated transactions and block trades. The timing and actual number of shares repurchased, if any, will depend upon several factors, including market conditions, business conditions, the trading price of our common stock and the nature of other investment opportunities available to us.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

Disclosures required pursuant to Section 13(r) of the Securities Exchange Act of 1934

Pursuant to Section 13(r) of the Exchange Act, we are required to include certain disclosures in our periodic reports if we or any of our "affiliates" (as defined in Rule 12b-2 under the Exchange Act) knowingly engaged in certain specified activities, transactions or dealings relating to Iran or with certain individuals or entities targeted by United States' economic sanctions during the period covered by the report. Disclosure is generally required even where the activities, transactions or dealings were conducted in compliance with applicable law. Neither we nor any of our controlled affiliates or subsidiaries knowingly engaged in any of the specified activities relating to Iran or otherwise engaged in any activities associated with Iran during the reporting period. However, because the SEC defines the term "affiliate" broadly, it includes any entity controlled by us as well as any person or entity that controlled us or is under common control with us.

The description of the activities below has been provided to us by Warburg Pincus LLC ("Warburg Pincus"), affiliates of which: (i) beneficially own more than 10% of our outstanding common stock and are members of our board of directors and (ii) beneficially own more than 10% of the outstanding common stock of and are members of the board of directors of Endurance International Group Holdings, Inc. (together with its subsidiaries, "EIGI"). EIGI may therefore be deemed to be under "common control" with us; however, this statement is not meant to be an admission that common control exists.

The disclosure below relates solely to activities conducted by EIGI. The disclosure does not relate to any activities conducted by Laredo or by Warburg Pincus and does not involve our or Warburg Pincus' management. Neither Laredo nor Warburg Pincus had any involvement in or control over the disclosed activities of EIGI, and neither Laredo nor Warburg Pincus has independently verified or participated in the preparation of the disclosure. Neither Laredo nor Warburg Pincus is representing as to the accuracy or completeness of the disclosure nor do we or Warburg Pincus undertake any obligation to correct or update it.

Laredo understands that EIGI intends to disclose in its next annual or quarterly SEC report that:

On September 11, 2019, EIGI's subsidiary P.D.R Solutions (U.S.) LLC ("PDR") suspended the domain name arabisc-haram.com, (the "Domain Name"), which was identified on September 10, 2019 by the Office of Foreign Assets Control ("OFAC"), as associated with Al Haram Commercial Company ("Al Haram"), a Specially Designated National ("SDN"), pursuant to 31 C.F.R. Part 594. The Domain Name was registered on November 13, 2017 through a third-party domain registrar that uses PDR's platform to sell, register and manage domain names for customers of such third-party domain registrar; there was no direct financial transaction between PDR and the registrant of the Domain Name. PDR debited the account of the third-party domain registrar a total of USD sixty cents ($0.60) as a fee for such third-party domain registrar's use of PDR's platform in connection with the Domain Name, all of which was debited prior to OFAC's designation of Al Haram. PDR reported the Domain Name to OFAC as potentially the property of an SDN subject to blocking pursuant to Executive Order 13224. To date, PDR has not received any correspondence from OFAC regarding this matter.

Item 6. Exhibits

Exhibit Number	Description
3.1	Amended and Restated Certificate of Incorporation of Laredo Petroleum Holdings, Inc. (incorporated by reference to Exhibit 3.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on December 22, 2011).
3.2	Certificate of Ownership and Merger, dated as of December 30, 2013 (incorporated by reference to Exhibit 3.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on January 6, 2014).
3.3	Second Amended and Restated Bylaws of Laredo Petroleum, Inc. (incorporated by reference to Exhibit 3.3 of Laredo's Annual Report on Form 10-K (File No. 001-35380) filed on February 17, 2016).
4.1	Form of Common Stock Certificate (incorporated by reference to Exhibit 4.1 of Laredo's Registration Statement on Form 8-A12B/A (File No. 001-35380) filed on January 7, 2014).
10.1#	Form of Outperformance Share Unit Award Agreement (incorporated by reference to Exhibit 10.8 of Laredo's Quarterly Report on Form 10-Q (File No. 001-35380) filed on August 1, 2019).
10.2*#	Payment and Release Agreement, dated October 1, 2019, between Laredo Petroleum, Inc. and Mr. Randy Foutch.
10.3*	Schedule 1, amended and restated as of October 30, 2019, to the Third Amendment to Fifth Amended and Restated Credit Agreement, dated as of April 19, 2018, among Laredo Petroleum, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, Laredo Midstream Services, LLC and Garden City Minerals, LLC, as guarantors and the banks signatory thereto.
10.4	Purchase and Sale Agreement, dated November 4, 2019, by and between Cordero Energy Resources LLC and Laredo Petroleum, Inc. (incorporated by reference to Exhibit 10.1 of Laredo's Current Report on Form 8-K (File No. 001-35380) filed on November 5, 2019).
31.1*	Certification of Chief Executive Officer Pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
31.2*	Certification of Chief Financial Officer Pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
32.1**	Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18. U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101	The following financial information from Laredo's Quarterly Report on Form 10-Q for the quarter ended September 30, 2019, formatted in Inline XBRL: (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Operations, (iii) Consolidated Statements of Stockholders' Equity, (iv) Consolidated Statements of Cash Flows and (v) Condensed Notes to the Consolidated Financial Statements.
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).
XML*	Extracted XBRL Instance Document.

* Filed herewith.

** Furnished herewith.

\# Management contract or compensatory plan or arrangement.

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 thereunto duly authorized.

LAREDO PETROLEUM, INC.

Date: November 6, 2019	By: /s/ Jason Pigott Jason Pigott *President and Chief Executive Officer* *(principal executive officer)*
Date: November 6, 2019	By: /s/ Michael T. Beyer Michael T. Beyer *Senior Vice President and Chief Financial Officer* *(principal financial officer & principal accounting officer)*