



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

## **Laredo Petroleum Announces 2016 Fourth-Quarter and Full-Year Financial and Operating Results**

### ***Increases Company Type Curves for Upper and Middle Wolfcamp***

**TULSA, OK - February 15, 2017** - Laredo Petroleum, Inc. (NYSE: LPI) (“Laredo” or the “Company”) today announced its 2016 fourth-quarter and full-year results. For the fourth quarter of 2016, the Company reported a net loss attributable to common stockholders of \$18.4 million, or \$0.08 per diluted share, which includes a loss on derivatives of \$43.6 million reflecting matured and new contracts and changes of the market prices in the forward curves of oil, natural gas liquids (“NGL”) and natural gas. Adjusted Net Income, a non-GAAP financial measure, for the fourth quarter of 2016 was \$38.8 million, or \$0.16 per adjusted diluted share. Adjusted EBITDA, a non-GAAP financial measure, for the fourth quarter of 2016, was \$134.9 million.

For the year ended December 31, 2016, the Company reported a net loss attributable to common stockholders of \$260.7 million, or \$1.16 per diluted share, including a non-cash full cost ceiling impairment charge of \$161.1 million taken in the first quarter of 2016. Adjusted Net Income for the year ended December 31, 2016 was \$112.6 million, or \$0.49 per adjusted diluted share, and Adjusted EBITDA was \$461.3 million. Please see supplemental financial information at the end of this news release for reconciliation of the non-GAAP financial measures.

### **2016 Highlights**

- Produced a Company record 53,141 barrels of oil equivalent (“BOE”) per day in the fourth quarter of 2016, resulting in full-year 2016 production growth of approximately 11% from full-year 2015
- Grew proved developed reserves organically by approximately 40% in 2016 at a proved developed finding and development (“F&D”) cost of \$5.12 per BOE
- Replaced 322% of production organically with proved developed reserves
- Completed 45 horizontal development wells in 2016 at an average anticipated rate of return on invested capital of greater than 40%
- Reduced unit lease operating expenses (“LOE”) to \$3.56 per BOE in the fourth quarter of 2016, resulting in a full-year 2016 unit LOE reduction of approximately 37% from full-year 2015
- Recognized approximately \$24 million of cash benefits from Laredo Midstream Services, LLC (“LMS”) field infrastructure investments through reduced capital and operating costs and increased revenue

- Received approximately \$185.6 million of net cash settlements on commodity derivatives that matured during 2016, increasing the average sales price for oil by \$20.34 per barrel and for natural gas by \$0.47 per thousand cubic feet compared to pre-hedged average sales prices
- Grew annual transported volumes on the Medallion Gathering & Processing, LLC ("Medallion-Midland Basin") system, of which LMS is a 49% owner, by 159% in 2016 to 39.3 million barrels of oil, with a fourth-quarter daily average rate of 129,087 barrels of oil per day ("BOPD")

"From the moment that Laredo leased its first acre in the Midland Basin, the Company's primary strategy has been maximizing Laredo's total value through efficient resource development," stated Randy A. Foutch, Chairman and Chief Executive Officer. "Building a contiguous acreage position, gathering data for the proprietary Earth Model, investing in field infrastructure, developing production corridors and forming a partnership to build the Medallion-Midland Basin system are all part of that goal. In 2016, our strategy provided a substantive, repeatable benefit to the Company."

"Laredo's 2016 development drilling activities achieved anticipated field level returns on invested capital exceeding 40% by leveraging a combination of factors and staying focused on our strategy. The Company's contiguous acreage position enabled the drilling of high-return, long and extended-reach laterals. We utilized the Earth Model to optimize location and landing point selection and completion design, resulting in substantial outperformance versus our historic Upper Wolfcamp, Middle Wolfcamp and Cline type curves. Our field infrastructure and production corridor assets drove capital and operating costs to levels among the lowest in the Midland Basin. These factors enabled Laredo to grow production 11% during the year, organically grow proved developed reserves 41% at a proved developed F&D cost of \$5.12 per BOE and fund our drilling program with operating cash flow. Utilizing our Earth Model to optimize location and landing point selection and completion design for wells has continued the strong performance of our drilling program in 2016 and has led the Company to increase its type curves for the Upper and Middle Wolfcamp to 1.3 million BOE."

"We believe 2017 is positioned to be another outstanding year for Laredo. We expect to continue capitalizing on past strategic investments while continually refining our development program. We anticipate drilling even longer laterals, further refining our completion techniques and testing multiple landing points within formations. Our prior infrastructure investments are expected to continue increasing efficiencies and lessen the impact to the Company of rising service costs. The potential to enhance the value of our acreage is still growing. We have multiple years of high-value inventory and our prior investments have positioned the Company to take full advantage of that potential."

### **Increased Type Curves**

Through the application of the Company's proprietary multivariate Earth Model to optimize landing points and the design and completion of horizontal wells, Laredo's development drilling results substantially outperformed the Company's historic type curves. As a result, Laredo has increased the type curves for 10,000-foot horizontal wells in the Upper and Middle Wolfcamp to 1.3 million BOE, from 1.1 million BOE and 1.0 million BOE,

respectively. The increases are driven by a 10% uplift in both oil and natural gas volumes to reflect the performance associated with utilization of the multivariate Earth Model. The remaining increase in natural gas volumes reflects historical production data showing gas production outperforming type-curve expectations in later years.

From this point forward, these increased type curves will be the basis for comparing production performance for horizontal wells in the Upper and Middle Wolfcamp within all Company press releases and presentations.

### **Operational Update**

In the fourth quarter of 2016, Laredo produced a Company record 53,141 BOE per day, up 32% from fourth-quarter 2015, resulting in production for full-year 2016 of 18.1 million BOE, an increase of approximately 11% from the 2015 volume. Laredo recognized anticipated field-level returns of greater than 40% for the 2016 development drilling program, driven by increasing average lateral lengths to approximately 10,000 feet, utilization of the multivariate Earth Model to optimize landing points and completions and efficiency-related cost reductions.

The Company completed 10 horizontal development wells in the fourth quarter of 2016 in two multi-well packages. The four-well Taylor package targeting the Middle Wolfcamp was completed early in the quarter utilizing 1,800 pounds of sand per lateral foot. This package is currently outperforming the oil type curve and three-stream type curve of the 1.3 million BOE Middle Wolfcamp type curve by 29% and 35%, respectively, adjusted for lateral length. The remaining six wells were developed as a package targeting the Upper Wolfcamp. These wells were completed late in the quarter and require longer-run data to make appropriate comparisons to Company type curves, although current production trends for the package are encouraging.

Fourth-quarter 2016 production growth was positively impacted by the timing of the seven-well Sugg 171/185 package, which was completed near the end of the third quarter of 2016. These wells targeted the Upper and Middle Wolfcamp and were completed utilizing 2,400 pounds of sand per lateral foot and were produced utilizing a managed drawdown protocol. The results of these larger completions are very encouraging as the package is currently outperforming the oil type curve and three-stream type curve of the 1.3 million BOE Upper and Middle Wolfcamp type curves by 41% and 24%, respectively, adjusted for lateral length. Production trends indicate the type curve outperformance may still be increasing and the Company will continue to monitor the results to determine the long-term, incremental uplift from both the larger completion and the utilization of a managed drawdown protocol.

Four of the wells in the Sugg 171/185 package were extended-reach laterals, with drilled lateral lengths averaging approximately 13,400 feet. The wells averaged 18 days to drill, from rig accept to rig release, the best of which was drilled in a Company record 16 days. The superior economics of drilling long laterals combined with the Company's success in executing extended-reach laterals is expected to continue to drive higher returns as the average lateral length increases in Laredo's overall development plan. The Company has identified more

than 2,000 locations that support lateral lengths of 10,000 feet or longer on its contiguous acreage base and expects the average drilled lateral length of its 2017 drilling program to be approximately 10,000 feet.

In 2016, Laredo completed 44 of its 45 horizontal development wells as multi-well packages. Through extensive data collection and analysis with the multivariate Earth Model, the Company has continued to optimize resource development to minimize the impact of pressure depletion on future drilling locations. Additionally, multi-well packages enable highly efficient batch drilling and completions operations which reduce well costs and minimize non-productive time. The Company's strategy of building production corridors and other field infrastructure enables the cost-efficient drilling and completion of multi-well packages. The completion of a five-well package requires approximately 3 million barrels of frac water in a two-week period. The Company's infrastructure handles the supply and takeaway of flowback and produced water for the multi-well packages. This facilitates execution logistics and reduces the risks and costs associated with the completion operations, all of which could diminish returns.

Lease operating expenses continue to be driven lower as costs benefit from the Company's prior investments in water handling infrastructure and centralized gas lift, as well as the increased activity along Laredo's production corridors. These infrastructure-related savings, which Laredo retains permanently, reduced fourth-quarter unit LOE by approximately \$0.51 per BOE. As a result, unit LOE decreased to \$3.56 per BOE in the fourth quarter of 2016, down approximately 39% from the 2015 rate of \$5.83 per BOE and down more than 7% sequentially from the third-quarter 2016 rate.

### **2017 Development Program**

The Company expects to complete 12 horizontal development wells in the first quarter of 2017. The wells are being drilled as a nine-well package and a package of three wells, with 11 wells targeting the Upper and Middle Wolfcamp and one targeting the Cline. The completion timing of the nine-well package is expected to push the commencement of production on both packages to the later part of the quarter. This is expected to result in first-quarter completions having minimal impact on first quarter production but contributing meaningfully to production growth in the second quarter of 2017.

Throughout 2017, Laredo expects to apply results from the completions optimization and multivariate Earth Model workflows to test several concepts that could, if successful, have a substantial positive impact on stockholder value. The Upper and Middle Wolfcamp have a combined average thickness greater than 1,000 feet across the Company's acreage with proven horizontal productivity across at least four distinct landing points within these two targets. Well packages designed to co-develop several landing points within the same target are planned in 2017, with the goal of adding additional high-value locations.

### **Laredo Midstream Services Update**

Laredo's midstream strategy of investing in field infrastructure continues to produce growing operating and financial benefits for the Company. LMS' oil and gas gathering, water system and centralized compression assets

generated a combined cash benefit and capital and operating cost savings of approximately \$5.5 million to the Company in the fourth quarter of 2016.

LMS' water system assets are a key component of the Company's field infrastructure and production corridor system. Water assets consist of approximately 78 miles of pipeline, a recycling plant capable of processing 30,000 barrels of water per day ("BWPD") and linked water storage assets with a storage capacity of more than 5 million barrels of water. In the fourth quarter of 2016, LMS' water system assets transported approximately 65% of the Company's produced water on pipe, of which 56% was recycled by Laredo, reducing the need for fresh water.

The Company's strategy of securing firm takeaway capacity led to its 49% ownership in the Medallion-Midland Basin system. Laredo's investment in the system generated income of \$3.1 million and Adjusted EBITDA, a non-GAAP financial measure, of \$6.4 million in the fourth quarter of 2016 and income of \$9.4 million and Adjusted EBITDA of \$20.4 million for full-year 2016, net to the Company's 49% interest in the system. Please see supplemental financial information at the end of this news release for reconciliation of the non-GAAP financial measures.

The Company's investment in the Medallion-Midland Basin system continues to add value as the system's throughput has grown rapidly. Upon completion of current projects, the system will consist of more than 650 miles of pipeline, of which more than 500 miles are six-inch pipe or larger. The system accesses many of the most productive areas of the Midland Basin, can deliver more than 500,000 BOPD into four delivery locations and has more than 520,000 net acres dedicated to the system or supporting firm transportation commitments. Approximately 80% of transported volumes are from third-party producers, up from approximately 35% at the inception of the system. In the fourth quarter of 2016, volumes grew to an average of approximately 129,000 BOPD, an increase of approximately 87% from the fourth quarter of 2015. Average daily volumes exited 2016 at approximately 133,000 BOPD and are expected to grow by greater than 75% by the end of 2017.

"The Medallion-Midland Basin system was built to provide flexibility to transport the Company's oil to delivery locations outside of the Midland market, enabling Laredo to access long-haul pipelines to the Gulf Coast and creates optionality for the best pricing," commented Mr. Foutch. "As other operators recognized the value of the system, Medallion expanded and the value of Laredo's 49% interest has grown dramatically. The original rationale for building the pipeline, to provide operational flexibility, has been realized through the Company's contract for 30,000 BOPD of firm capacity on the system. The investment also provides financial flexibility for Laredo as the EBITDA and value of the investment continue to grow."

### **Reserves and Locations**

Laredo's 2016 development drilling plan, in conjunction with upward performance revisions and operating cost reductions that increased the economic life of producing wells added 58 million BOE of proved developed reserves, replacing 322% of production. The exceptional well performance and operational efficiencies that reduced drilling and completion costs resulted in a proved developed F&D cost of \$5.12 per BOE.

Total proved reserves at year-end 2016 increased 41 million BOE to 167 million BOE, growing 33% from year-end 2015. Proved developed reserves increased 41% to 141 million BOE and represent 84% of total proved reserves, an increase from 80% at year-end 2015. Proved undeveloped ("PUD") reserves were essentially unchanged as Laredo, beginning in 2016, purposely reduced PUD bookings. This strategy enables the Company to develop its acreage in the most efficient manner possible and provides it the most flexibility to enhance shareholder value at prevailing conditions. The Company has identified more than 3,500 locations capable of generating at least a 10% field level rate of return in the current commodity price and service cost environment. Included in this count is approximately a decade of inventory, at the Company's current rig cadence, of horizontal wells capable of at least a 40% rate of return at current commodity prices and service costs.

The standardized measure of the Company's proved reserves at year-end 2016 was \$978.5 million, an increase of 18% from the standardized measure at year-end 2015 of \$830.7 million. The volume and value of the Company's proved reserves increased despite an 18% percent decrease in the price of oil and a 6% decrease in the price of natural gas and NGL used to calculate the value of the reserves.

### **2016 Capital Program**

Laredo outperformed its anticipated 2016 production while spending significantly less than planned. The Company executed its 2016 capital program for \$334 million, 20% below its \$420 million budget. The trend of higher production with lower capital expenditures throughout 2016 resulted in steadily increasing quarterly cash flow from operations, which fully funded the full-year capital program, excluding acquisitions and investments in the Medallion-Midland Basin system.

During the fourth quarter of 2016, Laredo invested approximately \$78.2 million in exploration and development activities, approximately \$12.3 million in bolt-on acquisitions and approximately \$12.6 million in infrastructure held by LMS and the Medallion-Midland Basin system. For full-year 2016, Laredo invested approximately \$317.2 million in exploration and development activities, approximately \$148.9 million in bolt-on acquisitions and approximately \$45.2 million in infrastructure held by LMS and the Medallion-Midland Basin system.

### **Liquidity**

At December 31, 2016, the Company had cash and cash equivalents of approximately \$33 million and undrawn capacity under the senior secured credit facility of \$745 million. At February 14, 2017, the Company had cash and cash equivalents of approximately \$24 million and undrawn capacity under the senior secured credit facility of \$800 million, resulting in total liquidity of approximately \$824 million.

### **Commodity Derivatives**

Laredo maintains a disciplined hedging program to reduce the variability in its anticipated cash flow due to fluctuations in commodity prices. At December 31, 2016, the Company had hedges in place for 2017 for 6,852,875 barrels of oil at a weighted-average floor price of \$55.82 per barrel, representing approximately 70% of anticipated oil production in 2017. Approximately 80% of total anticipated oil production in 2017 retains significant upside to

an increase in the price of oil with those volumes either having a weighted-average ceiling price of \$86.00 per barrel or no ceiling at all. Additionally, the Company had hedges in place for 2017 for 27,056,500 million British thermal units ("MMBtu") of natural gas at a WAHA weighted-average floor price of \$2.75 per MMBtu, 444,000 barrels of ethane at \$11.24 per barrel and 375,000 barrels of propane at \$22.26 per barrel.

## Guidance

The Company is reiterating its previously stated anticipated full-year 2017 production growth guidance of at least 15%. The table below reflects the Company's production guidance for the first and second quarters of 2017 and cost guidance for the first quarter of 2017:

	<u>1Q-2017</u>	<u>2Q-2017</u>
Production (MBOE/d) .....	52 - 54	55 - 58
Product % of total production:		
Crude oil .....	44% - 46%	45% - 47%
Natural gas liquids .....	27% - 28%	*
Natural gas .....	27% - 28%	*
Price Realizations (pre-hedge):		
Crude oil (% of WTI) .....	~90%	*
Natural gas liquids (% of WTI) .....	~32%	*
Natural gas (% of Henry Hub) .....	~72%	*
Operating Costs & Expenses:		
Lease operating expenses (\$/BOE) .....	\$3.50 - \$4.00	*
Midstream expenses (\$/BOE) .....	\$0.20 - \$0.30	*
Production and ad valorem taxes (% of oil, NGL and natural gas revenue) .....	6.75%	*
General and administrative expenses:		
Cash (\$/BOE) .....	\$3.35 - \$3.85	*
Non-cash stock-based compensation (\$/BOE) .....	\$2.00 - \$2.25	*
Depletion, depreciation and amortization (\$/BOE) .....	\$7.50 - \$8.00	*

\* Not provided

## Fourth-Quarter and Full-Year 2016 Earnings Conference Call

Laredo will host a conference call on Thursday, February 16, 2017 at 7:30 a.m. CT (8:30 a.m. ET) to discuss its fourth-quarter and full-year 2016 financial and operating results and management's outlook. Individuals who would like to participate on the call should dial 877.930.8286 (international dial-in 253.336.8309), using conference code 53302066 or listen to the call via the Company's website at [www.laredopetro.com](http://www.laredopetro.com), under the tab for "Investor Relations." A telephonic replay will be available approximately two hours after the call on February 16, 2017 through Thursday, February 23, 2017. Participants may access this replay by dialing 855.859.2056, using conference code 53302066.

## About Laredo

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

the transportation of oil and natural gas from such properties, primarily in the Permian Basin in West Texas.

Additional information about Laredo may be found on its website at [www.laredopetro.com](http://www.laredopetro.com).

### ***Forward-Looking Statements***

*This press release and any oral statements made regarding the subject of this release, including in the conference call referenced herein, contain forward-looking statements as defined under Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, that address activities that Laredo assumes, plans, expects, believes, intends, projects, estimates or anticipates (and other similar expressions) will, should or may occur in the future are forward-looking statements. The forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events.*

*General risks relating to Laredo include, but are not limited to, the decline in prices of oil, natural gas liquids and natural gas and the related impact to financial statements as a result of asset impairments and revisions to reserve estimates, and other factors, including those and other risks described in its Annual Report on Form 10-K for the year ended December 31, 2015, and those set forth from time to time in other filings with the Securities Exchange Commission ("SEC") including, but not limited to, its Annual Report on Form 10-K for the year ended December 31, 2016, to be filed with the SEC. These documents are available through Laredo's website at [www.laredopetro.com](http://www.laredopetro.com) under the tab "Investor Relations" or through the SEC's Electronic Data Gathering and Analysis Retrieval System at [www.sec.gov](http://www.sec.gov). Any of these factors could cause Laredo's actual results and plans to differ materially from those in the forward-looking statements. Therefore, Laredo can give no assurance that its future results will be as estimated. Laredo does not intend to, and disclaims any obligation to, update or revise any forward-looking statement.*

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



**Laredo Petroleum, Inc.**  
**Condensed consolidated statements of operations**

(in thousands, except per share data)	Three months ended December 31,		Year ended December 31,	
	2016	2015	2016	2015
	(unaudited)		(unaudited)	
Revenues:				
Oil, NGL and natural gas sales .....	\$ 136,012	\$ 83,455	\$ 426,485	\$ 431,734
Midstream service revenues.....	2,421	1,640	8,342	6,548
Sales of purchased oil .....	45,881	38,180	162,551	168,358
Total revenues .....	<u>184,314</u>	<u>123,275</u>	<u>597,378</u>	<u>606,640</u>
Costs and expenses:				
Lease operating expenses.....	17,407	21,643	75,327	108,341
Production and ad valorem taxes .....	7,103	6,411	28,586	32,892
Midstream service expenses .....	1,251	1,583	4,077	5,846
Minimum volume commitments.....	627	—	2,209	5,235
Costs of purchased oil.....	48,346	41,760	169,536	174,338
General and administrative .....	25,698	22,449	91,756	90,425
Restructuring expenses .....	—	—	—	6,042
Accretion of asset retirement obligations .....	896	652	3,483	2,423
Depletion, depreciation and amortization.....	37,526	66,893	148,339	277,724
Impairment expense.....	—	977,561	162,027	2,374,888
Total costs and expenses .....	<u>138,854</u>	<u>1,138,952</u>	<u>685,340</u>	<u>3,078,154</u>
Operating income (loss).....	<u>45,460</u>	<u>(1,015,677)</u>	<u>(87,962)</u>	<u>(2,471,514)</u>
Non-operating income (expense):				
Gain (loss) on derivatives, net .....	(43,642)	72,455	(87,425)	214,291
Income from equity method investee.....	3,144	2,214	9,403	6,799
Interest expense.....	(23,004)	(23,487)	(93,298)	(103,219)
Loss on early redemption of debt.....	—	—	—	(31,537)
Other, net.....	(379)	(152)	(1,457)	(1,701)
Non-operating income (expense), net .....	<u>(63,881)</u>	<u>51,030</u>	<u>(172,777)</u>	<u>84,633</u>
Loss before income taxes.....	<u>(18,421)</u>	<u>(964,647)</u>	<u>(260,739)</u>	<u>(2,386,881)</u>
Income tax benefit:				
Deferred .....	—	—	—	176,945
Total income tax benefit.....	<u>—</u>	<u>—</u>	<u>—</u>	<u>176,945</u>
Net loss.....	<u>\$ (18,421)</u>	<u>\$ (964,647)</u>	<u>\$ (260,739)</u>	<u>\$ (2,209,936)</u>
Net loss per common share:				
Basic.....	\$ (0.08)	\$ (4.57)	\$ (1.16)	\$ (11.10)
Diluted.....	\$ (0.08)	\$ (4.57)	\$ (1.16)	\$ (11.10)
Weighted-average common shares outstanding:				
Basic.....	238,047	211,255	225,512	199,158
Diluted.....	238,047	211,255	225,512	199,158

**Laredo Petroleum, Inc.**  
**Condensed consolidated balance sheets**

<b>(in thousands)</b>	<b>December 31, 2016</b>	<b>December 31, 2015</b>
Assets:	(unaudited)	(unaudited)
Current assets .....	\$ 154,777	\$ 332,232
Property and equipment, net .....	1,366,867	1,200,255
Other noncurrent assets .....	260,702	280,800
Total assets .....	<u>\$ 1,782,346</u>	<u>\$ 1,813,287</u>
Liabilities and stockholders' equity:		
Current liabilities .....	\$ 187,945	\$ 216,815
Long-term debt, net .....	1,353,909	1,416,226
Other noncurrent liabilities .....	59,919	48,799
Stockholders' equity .....	180,573	131,447
Total liabilities and stockholders' equity .....	<u>\$ 1,782,346</u>	<u>\$ 1,813,287</u>

**Laredo Petroleum, Inc.**  
**Condensed consolidated statements of cash flows**

(in thousands)	Three months ended December 31,		Year ended December 31,	
	2016	2015	2016	2015
	(unaudited)		(unaudited)	
Cash flows from operating activities:				
Net loss.....	\$ (18,421)	\$ (964,647)	\$ (260,739)	\$ (2,209,936)
Adjustments to reconcile net loss to net cash provided by operating activities:				
Deferred income tax benefit.....	—	—	—	(176,945)
Depletion, depreciation and amortization .....	37,526	66,893	148,339	277,724
Impairment expense .....	—	977,561	162,027	2,374,888
Loss on early redemption of debt.....	—	—	—	31,537
Non-cash stock-based compensation, net of amounts capitalized .....	9,667	6,576	29,229	24,509
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net .....	43,642	(72,455)	87,425	(214,291)
Cash settlements received for matured derivatives, net.....	37,655	79,402	195,281	255,281
Cash settlements received for early terminations of derivatives, net.....	—	—	80,000	—
Cash premiums paid for derivatives .....	(2,697)	(1,249)	(89,669)	(5,167)
Amortization of debt issuance costs .....	1,048	1,115	4,279	4,727
Other, net.....	(1,473)	(1,159)	(10,127)	(4,525)
Cash flows from operations before changes in working capital .....	106,947	92,037	346,045	357,802
Changes in working capital.....	4,016	(2,839)	10,669	(46,055)
Changes in other noncurrent liabilities and fair value of performance unit awards .....	(122)	1,245	(419)	4,200
Net cash provided by operating activities.....	110,841	90,443	356,295	315,947
Cash flows from investing activities:				
Deposit received for sale of oil and natural gas properties .....	3,000	—	3,000	—
Capital expenditures:				
Acquisitions of oil and natural gas properties.....	(9,060)	—	(124,660)	—
Oil and natural gas properties .....	(83,944)	(97,666)	(360,679)	(588,017)
Midstream service assets.....	(1,009)	(222)	(5,240)	(35,459)
Other fixed assets.....	(6,629)	(586)	(7,611)	(9,125)
Investment in equity method investee.....	(10,897)	(36,844)	(69,609)	(99,855)
Proceeds from dispositions of capital assets, net of selling costs .....	32	(312)	397	64,949
Net cash used in investing activities .....	(108,507)	(135,630)	(564,402)	(667,507)
Cash flows from financing activities:				
Borrowings on Senior Secured Credit Facility .....	25,000	—	239,682	310,000
Payments on Senior Secured Credit Facility .....	(25,000)	—	(304,682)	(475,000)
Issuance of March 2023 Notes.....	—	—	—	350,000
Redemption of January 2019 Notes.....	—	—	—	(576,200)
Proceeds from issuance of common stock, net of offering costs .....	—	—	276,052	754,163
Other, net.....	(22)	(62)	(1,427)	(9,570)
Net cash (used in) provided by financing activities.....	(22)	(62)	209,625	353,393
Net increase (decrease) in cash and cash equivalents.....	2,312	(45,249)	1,518	1,833
Cash and cash equivalents, beginning of period.....	30,360	76,403	31,154	29,321
Cash and cash equivalents, end of period .....	\$ 32,672	\$ 31,154	\$ 32,672	\$ 31,154

**Laredo Petroleum, Inc.**  
**Selected operating data**

	Three months ended December 31,		Year ended December 31,	
	2016	2015	2016	2015
	(unaudited)		(unaudited)	
Sales volumes:				
Oil (MBbl) .....	2,274	1,656	8,442	7,610
NGL (MBbl) .....	1,293	1,033	4,784	4,267
Natural gas (MMcf) .....	7,935	6,153	29,535	26,816
Oil equivalents (MBOE) <sup>(1)(2)</sup> .....	4,889	3,714	18,149	16,346
Average daily sales volumes (BOE/D) <sup>(2)</sup> .....	53,141	40,368	49,586	44,782
% Oil <sup>(2)</sup> .....	46%	45%	47%	47%
Average sales prices:				
Oil, realized (\$/Bbl) <sup>(3)</sup> .....	\$ 43.98	\$ 36.97	\$ 37.73	\$ 43.27
NGL, realized (\$/Bbl) <sup>(3)</sup> .....	14.79	11.06	11.91	11.86
Natural gas, realized (\$/Mcf) <sup>(3)</sup> .....	2.13	1.76	1.73	1.93
Average price, realized (\$/BOE) <sup>(3)</sup> .....	27.82	22.47	23.50	26.41
Oil, hedged (\$/Bbl) <sup>(4)</sup> .....	58.92	80.61	58.07	74.41
NGL, hedged (\$/Bbl) <sup>(4)</sup> .....	14.79	11.06	11.91	11.86
Natural gas, hedged (\$/Mcf) <sup>(4)</sup> .....	2.26	2.72	2.20	2.42
Average price, hedged (\$/BOE) <sup>(4)</sup> .....	34.97	43.51	33.73	41.71
Average costs per BOE sold:				
Lease operating expenses .....	\$ 3.56	\$ 5.83	\$ 4.15	\$ 6.63
Production and ad valorem taxes .....	1.45	1.73	1.58	2.01
Midstream service expenses .....	0.26	0.43	0.22	0.36
General and administrative:				
Cash .....	3.28	4.27	3.45	4.03
Non-cash stock-based compensation, net of amounts capitalized .....	1.98	1.77	1.61	1.50
Depletion, depreciation and amortization .....	7.68	18.01	8.17	16.99
Total .....	<u>\$ 18.21</u>	<u>\$ 32.04</u>	<u>\$ 19.18</u>	<u>\$ 31.52</u>

- (1) BOE is calculated using a conversion rate of six Mcf per one Bbl.
- (2) The volumes presented are based on actual results and are not calculated using the rounded numbers presented in the table above.
- (3) Realized oil, NGL and natural gas prices are the actual prices realized at the wellhead adjusted for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. The prices presented are based on actual results and are not calculated using the rounded numbers presented in the table above.
- (4) Hedged prices reflect the after-effects of our hedging transactions on our average sales prices. Our calculation of such after-effects includes current period settlements of matured derivatives in accordance with GAAP and an adjustment to reflect premiums incurred previously or upon settlement that are attributable to instruments that settled in the period. The prices presented are based on actual results and are not calculated using the rounded numbers presented in the table above.

**Laredo Petroleum, Inc.**  
**Costs incurred**

Costs incurred in the acquisition, exploration and development of oil, NGL and natural gas assets are presented below:

<b>(in thousands)</b>	<b>Three months ended December 31,</b>		<b>Year ended December 31,</b>	
	<b>2016</b>	<b>2015</b>	<b>2016</b>	<b>2015</b>
	(unaudited)		(unaudited)	
Property acquisition costs:				
Evaluated <sup>(1)</sup> .....	\$ —	\$ —	\$ 5,905	\$ —
Unevaluated .....	9,123	—	119,923	—
Exploration costs.....	7,583	4,540	41,333	20,697
Development costs <sup>(2)</sup> .....	73,839	118,936	298,942	500,577
Total costs incurred.....	\$ 90,545	\$ 123,476	\$ 466,103	\$ 521,274

- (1) Evaluated property acquisition costs include \$1.1 million in asset retirement obligations for the year ended December 31, 2016.
- (2) Development costs include \$2.0 million and \$12.1 million in asset retirement obligations for the three months ended December 31, 2016 and 2015, respectively, and \$2.5 million and \$13.4 million for the years ended December 31, 2016 and 2015, respectively.

## **Laredo Petroleum, Inc.**

### **Supplemental reconciliations of GAAP to non-GAAP financial measures**

#### **Non-GAAP financial measures**

The non-GAAP financial measures of Adjusted Net Income, Adjusted EBITDA, PV-10 and proved developed Finding & Development Cost, 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 flow from operating activities. Adjusted Net Income, Adjusted EBITDA, PV-10 or proved developed Finding and Development Cost should not be considered in isolation or as a substitute for GAAP measures, such as net income or loss, operating income or loss, standardized measure of discounted future net cash flows or any other GAAP measure of liquidity or financial performance.

#### ***Adjusted Net Income (Unaudited)***

Adjusted Net Income is a non-GAAP financial measure we use to evaluate performance, prior to deferred income taxes, gains or losses on derivatives, cash settlements of matured derivatives, cash settlements on early terminated derivatives, cash premiums paid for derivatives, impairment expense, restructuring expenses, loss on early redemption of debt, buyout of minimum volume commitment, gains or losses on disposal of assets, write-off of debt issuance costs and bad debt expense and after applying adjusted income tax expense. We believe Adjusted Net Income helps investors in the oil and natural gas industry to measure and compare our performance to other oil and natural gas companies by excluding from the calculation items that can vary significantly from company to company depending upon accounting methods, the book value of assets and other non-operational factors.

Including a higher weighted-average common shares outstanding in the denominator of a diluted per-share computation results in an anti-dilutive per share amount when an entity is in a loss position. As such, our net income (loss) (GAAP) per common share calculation utilizes the same denominator for both basic and diluted net income (loss) per common share. However, our calculation of Adjusted Net Income (non-GAAP) results in income for all periods presented. Therefore, we believe it appropriate and more conservative to calculate an Adjusted diluted weighted-average common shares outstanding utilizing our fully dilutive weighted-average common shares. As such, for each of the periods ending December 31, 2016 and 2015, we present a line item that calculates Adjusted Net Income per Adjusted diluted common share. Accordingly, the prior periods' Adjusted Net Income has been modified for comparability.

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

(in thousands, except for per share data, unaudited)	Three months ended December 31,		Year ended December 31,	
	2016	2015	2016	2015
Net loss.....	\$ (18,421)	\$ (964,647)	\$ (260,739)	\$ (2,209,936)
Plus:				
Deferred income tax benefit.....	—	—	—	(176,945)
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net.....	43,642	(72,455)	87,425	(214,291)
Cash settlements received for matured derivatives, net.....	37,655	79,402	195,281	255,281
Cash settlements received for early terminations of derivatives, net.....	—	—	80,000	—
Cash premiums paid for derivatives.....	(2,697)	(1,249)	(89,669)	(5,167)
Impairment expense.....	—	977,561	162,027	2,374,888
Restructuring expenses.....	—	—	—	6,042
Loss on early redemption of debt.....	—	—	—	31,537
Buyout of minimum volume commitment.....	—	—	—	3,014
Loss on disposal of assets, net.....	411	190	790	2,127
Write-off of debt issuance costs.....	—	—	842	—
Bad debt expense.....	—	148	—	255
Adjusted net income before adjusted income tax expense.....	60,590	18,950	175,957	66,805
Adjusted income tax expense <sup>(1)</sup> .....	(21,812)	(6,822)	(63,345)	(24,050)
Adjusted Net Income.....	\$ 38,778	\$ 12,128	\$ 112,612	\$ 42,755
Net loss per common share:				
Basic.....	\$ (0.08)	\$ (4.57)	\$ (1.16)	\$ (11.10)
Diluted.....	\$ (0.08)	\$ (4.57)	\$ (1.16)	\$ (11.10)
Adjusted Net Income per common share:				
Basic.....	\$ 0.16	\$ 0.06	\$ 0.50	\$ 0.21
Adjusted diluted.....	\$ 0.16	\$ 0.06	\$ 0.49	\$ 0.21
Weighted-average common shares outstanding:				
Basic.....	238,047	211,255	225,512	199,158
Diluted.....	238,047	211,255	225,512	199,158
Adjusted diluted.....	243,507	214,359	228,676	202,216

(1) Adjusted income tax expense is calculated by applying a tax rate of 36%.

### *Adjusted EBITDA (Unaudited)*

Adjusted EBITDA is a non-GAAP financial measure that we define as net income or loss plus adjustments for deferred income tax expense or benefit, depletion, depreciation and amortization, bad debt expense, impairment expense, non-cash stock-based compensation, accretion of asset retirement obligations, restructuring expenses, gains or losses on derivatives, cash settlements received for matured derivatives, cash settlements on early terminated and modified derivatives, cash premiums paid for derivatives, interest expense, write-off of debt issuance costs, gains or losses on disposal of assets, loss on early redemption of debt, buyout of minimum volume commitment, income or loss from equity method investee and proportionate Adjusted EBITDA of equity method investee. Adjusted EBITDA provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, working capital movement or tax position. Adjusted EBITDA does not represent funds available for discretionary use because those funds are required for debt service, capital expenditures and 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, 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.

For the year ended December 31, 2016, we changed the methodology for calculating Adjusted EBITDA by including adjustments for both accretion of asset retirement obligations and our proportionate share of our equity method investee's Adjusted EBITDA. Accordingly, the prior periods' Adjusted EBITDA has been modified for comparability.



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

(in thousands, unaudited)	Three months ended December 31,		Year ended December 31,	
	2016	2015	2016	2015
Net loss.....	\$ (18,421)	\$ (964,647)	\$ (260,739)	\$ (2,209,936)
Plus:				
Deferred income tax benefit.....	—	—	—	(176,945)
Depletion, depreciation and amortization.....	37,526	66,893	148,339	277,724
Bad debt expense.....	—	148	—	255
Impairment expense.....	—	977,561	162,027	2,374,888
Non-cash stock-based compensation, net of amounts capitalized.....	9,667	6,576	29,229	24,509
Accretion of asset retirement obligations.....	896	652	3,483	2,423
Restructuring expenses.....	—	—	—	6,042
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net.....	43,642	(72,455)	87,425	(214,291)
Cash settlements received for matured derivatives, net.....	37,655	79,402	195,281	255,281
Cash settlements received for early terminations of derivatives, net.....	—	—	80,000	—
Cash premiums paid for derivatives.....	(2,697)	(1,249)	(89,669)	(5,167)
Interest expense.....	23,004	23,487	93,298	103,219
Write-off of debt issuance costs.....	—	—	842	—
Loss on disposal of assets, net.....	411	190	790	2,127
Loss on early redemption of debt.....	—	—	—	31,537
Buyout of minimum volume commitment.....	—	—	—	3,014
Income from equity method investee.....	(3,144)	(2,214)	(9,403)	(6,799)
Proportionate Adjusted EBITDA of equity method investee <sup>(1)</sup> .....	6,386	3,609	20,367	9,383
Adjusted EBITDA.....	<u>\$ 134,925</u>	<u>\$ 117,953</u>	<u>\$ 461,270</u>	<u>\$ 477,264</u>

(1) Proportionate Adjusted EBITDA of Medallion, our equity method investee, is calculated as follows:

(in thousands, unaudited)	Three months ended December 31,		Year ended December 31,	
	2016	2015	2016	2015
Income from equity method investee.....	\$ 3,144	\$ 2,214	\$ 9,403	\$ 6,799
Adjusted for proportionate share of:				
Depreciation and amortization.....	3,242	1,395	10,964	4,061
Buyout of minimum volume commitment.....	—	—	—	(1,477)
Proportionate Adjusted EBITDA of equity method investee.....	<u>\$ 6,386</u>	<u>\$ 3,609</u>	<u>\$ 20,367</u>	<u>\$ 9,383</u>

**PV-10 (Unaudited)**

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

<b>(in thousands, unaudited)</b>	<b>December 31, 2016</b>
Pre-tax PV-10 .....	\$ 978,494
Present value of future income taxes discounted at 10% .....	—
Standardized measure of discounted future net cash flows.....	<u>\$ 978,494</u>

**Proved Developed Finding and Development Cost (Unaudited)**

Proved developed finding and development ("F&D") cost is calculated by dividing (x) development costs for the period, by (y) proved developed reserve additions for the period, defined as the change in proved developed reserves, less purchased reserves, plus sold reserves and plus sales volumes during the period. The method we use to calculate our proved developed F&D cost may differ significantly from methods used by other companies to compute similar measures. As a result, our proved developed F&D cost may not be comparable to similar measures provided by other companies. We believe that providing the measure of proved development F&D cost is useful in evaluating the cost, on a per BOE basis, to added proved developed reserves.

However, this measure is provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP. Due to various factors, including timing differences in the addition of proved reserves and the related costs to develop those reserves, proved developed F&D cost do not necessarily reflect precisely the costs associated with particular proved reserves. As a result of various factors that could materially affect the timing and amounts of future increases in proved reserves and the timing and amounts of future costs, we cannot assure you that our future proved developed F&D cost will not differ materially from those presented.

<b>(\$ in thousands, except per BOE amount, reserves and sales volumes in MBOE, unaudited)</b>	<b>F&amp;D</b>
Development costs (x).....	\$ 298,942
Proved developed reserves:	
As of December 31, 2016 .....	141,155
As of December 31, 2015 .....	(100,395)
Proved developed reserve additions .....	40,760
Less purchased proved developed reserves during 2016 .....	(529)
Plus 2016 sales volumes .....	18,149
Drill bit proved developed reserve additions (y).....	<u>58,380</u>
F&D cost per BOE .....	<u>\$ 5.12</u>

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Contacts:

Ron Hagood: (918) 858-5504 - [RHagood@laredopetro.com](mailto:RHagood@laredopetro.com)