February 26, 2019

Callon Petroleum Company Announces Fourth Quarter 2018 Results

HOUSTON, Feb. 26, 2019 /PRNewswire/ -- Callon Petroleum Company (NYSE: CPE) ("Callon" or the "Company") today reported results of operations for the three months and full-year ended December 31, 2018.

Presentation slides accompanying this earnings release are available on the Company's website at www.callon.com located on the "Presentations" page within the Investors section of the site.

2018 Highlights

- Full-year 2018 production of 32.9 Mboe/d (79% oil), an increase of 44% over 2017 volumes and at the top of the 2018 guidance range with a higher oil cut
- Year-end proved reserves of 238.5 MMboe (76% oil), a year-over-year increase of 74% combined with an oil content that has remained consistently over 75% since commencing horizontal development in 2012
- Proved reserve additions replaced 690% of 2018 production at a "drill-bit" finding and development cost [(i)] of $7.03 per Boe and a proved developed finding and development cost[(i)] of $13.40 per Boe
- Generated an operating margin of $40.16 per Boe reflecting our high level of oil volumes, proactive investments in infrastructure and offtake relationships, and cost structure improvements
- Realized net income of $300.4 million and generated Adjusted EBITDA[(i)] of $432.5 million relative to cash drilling and completion capital expenditures of $403.5 million
- Completed the acquisition of 34,523 net working interest acres and 1,530 net mineral acres within our core operating areas, more than doubling our Delaware footprint since 2017, and also traded 4,420 net acres to further long-lateral development
- Divested 3,540 net acres as part of ongoing initiatives to monetize non-core assets and enhance returns on capital
- Executed firm transportation and marketing agreements that are expected to transition 25 MBbl/d of our gross oil production to a combination of Gulf Coast, Brent and waterborne pricing January 2020

Fourth Quarter 2018 Highlights

- Fourth quarter 2018 production of 41.1 Mboe/d (81% oil), an increase of 55% over fourth quarter 2017 volumes and a sequential increase of 18%
- Generated $151.6 million of cash provided by operating activities, exceeding cash used in investing activities for operational capital additions of $127.8 million in the

development of oil and natural gas properties
- Began building an inventory of drilled, uncompleted wells to support our transition to larger scale development in the Delaware Basin in 2019

Joe Gatto, President and Chief Executive Officer commented, "The past year represented a significant inflection point in the maturity of our Permian operations and progression to a development model that will drive increased capital efficiency and corporate returns. The critical steps we took this past year will assist in our transition to full-field development, employing larger pad concepts as part of an integrated technical and operational approach to multi-zone resource monetization. We enter 2019 with a substantial proved reserve base approaching 250 million BOE that has consistently carried one of the highest percentages of oil across our peer group since we commenced horizontal development. As part of the maturation of our business, our corporate decline rates have also moderated over the last few years, setting the stage for decreasing capital intensity as more capital will contribute to incremental production growth and less capital will be needed for replacement. This dynamic, combined with the impact of larger scale program development in the Delaware Basin that will emerge around mid-year, provides a solid foundation for quality growth in 2019 and beyond." He continued, "As the industry landscape evolves, operators are faced with the choice of pursuing short-term benefits at the expense of future reinvestment opportunities, capital efficiency and longer-term growth trajectory. We remain steadfast in our long-term value focus, employing resource development concepts and pace of activity that will keep us on a path to sustainable free cash flow generation at WTI prices in the low $50s from repeatable investments in our high quality asset base."

Operations Update

At December 31, 2018, we had 466 gross (364 net) horizontal wells producing from eight established flow units in the Permian Basin. Net daily production for the three months ended December 31, 2018 grew 55% to 41.1 Mboe/d (81% oil) as compared to the same period of 2017. Full year production for 2018 averaged 32.9 Mboe/d (79% oil) reflecting growth of 44% over 2017 volumes.

For the three months ended December 31, 2018, we drilled 17 gross (15.3 net) horizontal wells, and placed a combined 19 gross (17.2 net) horizontal wells on production. Wells placed on production during the quarter totaled approximately 106,000 net lateral feet and were completed in the upper and lower intervals of the Lower Spraberry, Wolfcamp A and Wolfcamp B within the Midland Basin and the Lower Wolfcamp A within the Delaware Basin.

Midland Basin

We brought nine gross wells online in the Monarch area in the fourth quarter achieving an average peak 24-hour rate of 235 Boe per thousand lateral feet with an average oil cut of 86%. More recent wells in the Monarch area demonstrate consistency in our well results across multiple zones with the Casselman 40 pad, a Wolfcamp A and B co-development project, averaging approximately 150 barrels of oil per thousand lateral feet in early time flowback. Additional multi-interval pad development projects targeting both upper and lower flow units in the Lower Spraberry, coupled with a Middle Spraberry well, are currently flowing back with encouraging early time results relative to offsetting wells.

In the WildHorse area in Howard County, we placed on production a three-well pad which produced an average of approximately 190 Boe (90% oil) per day per thousand lateral feet per well through the first 30 days. During the first quarter of 2019, we will be completing a five-well pad developing the Wolfcamp A on 10-well spacing, building upon our successful pilot test in the Fairway area of WildHorse last year.

The previously disclosed outage at a third party gas processing facility in Martin County has persisted into the first quarter as the plant is brought back on a gradual basis. We expect a normalized level of gas processing to resume during the month of March. We estimate lost natural gas and NGL volumes during the fourth quarter of approximately 9,800 Mcfe/d, with no impact to our oil volumes. We currently expect an impact of approximately 4,000 Mcfe/d in the first quarter of 2019.

Delaware Basin

At our Spur area in Ward County, we placed on production six gross wells with an average completed lateral length of just under 8,000 feet. A two-well development including the Teewinot A1 04LA and A2 05LA wells have demonstrated strong performance since being turned to production in December. The two wells averaged approximately 390 Boe (85% oil) per day per thousand lateral feet through the first 70 days of production resulting in total production of nearly 260,000 Boe in just over two months. The Rock Garden A 08 LA and 01 LA wells, which were completed separately and brought on production during the third and latter part of the fourth quarter respectively, have each averaged approximately 1,300 Boe (88% oil) per day over their first 60 days. Additionally, the Limber Pine A2 05LA and A1 01LA wells, brought on production in November and December respectively, have each also averaged approximately 1,175 Boe (85% oil) per day through their first 60 days on production.

We continue to build an inventory of drilled, uncompleted wells at Spur in preparation for larger pad development projects which are slated for completion during the second half of the year and are expected to provide meaningful production growth into year-end 2019 and early 2020. As part of our increased scale of planned development, we continue to enhance our field operations through an addition to our existing recycling facility. The addition will bring our total recycling capacity to 60,000 barrels of water per day, reducing our sourcing and disposal costs on a go forward basis while also reducing our environmental impact in the regional area.

Following the acquisition of a significant producing asset base in September 2018, we have advanced several initiatives to improve operational reliability and reduce operating costs. We will be accelerating our maintenance and field optimization projects over the next three months, requiring a voluntary shut-in of production during that time. We expect this deferral of production will impact our productive capacity by roughly 1,000 Boe/d during the first quarter with a decreased impact in the second quarter as the project is expected to be completed in April.

Capital Expenditures

For the twelve months ended December 31, 2018, we incurred $546.1 million in cash operational capital expenditures (including other items) of $127.8 million in the fourth quarter, which represented a $21.7 million decrease from the third quarter. In the fourth quarter, we spent approximately $92.4 million on drilling and completion and $35.4 million on facilities, equipment, and other items on a cash basis. Total capital expenditures, inclusive of capitalized expenses, are detailed below on an accrual and cash basis (in thousands):

	Three Months Ended December 31, 2018			
	Operational Capital [(a)]	Capitalized Interest	Capitalized G&A	Total Capital Expenditures
Cash basis [(b)]	$ 127,823	$ 20,159	$ 7,839	$ 155,821
Timing adjustments [(c)]	13,354	(2,659)	—	10,695
Non-cash items	—	—	353	353
Accrual basis	$ 141,177	$ 17,500	$ 8,192	$ 166,869

(a) Includes seismic, land and other items.
(b) Cash basis is presented here to help users of financial information reconcile amounts from the cash flow statement to the balance sheet by accounting for timing related changes in working capital that align with our development pace and rig count.
(c) Includes timing adjustments related to cash disbursements in the current period for capital expenditures incurred in the prior period.

Operating and Financial Results

The following table presents summary information for the periods indicated:

	Three Months Ended,		
	December 31, 2018	September 30, 2018	December 31, 2017
Net production			
Oil (MBbls)	3,076	2,521	1,936
Natural gas (MMcf)	4,225	4,144	3,018
Total (Mboe)	3,780	3,212	2,439
Average daily production (Boe/d)	41,087	34,913	26,511
% oil (Boe basis)	81 %	78 %	79 %
Oil and natural gas revenues (in thousands)			
Oil revenue	$ 150,398	$ 142,601	$ 104,132
Natural gas revenue [(a)]	11,497	18,613	14,081
Total operating revenues	161,895	161,214	118,213
Impact of settled derivatives	(1,594)	(9,239)	(4,501)
Adjusted Total Revenue [(i)]	$ 160,301	$ 151,975	$ 113,712
Average realized sales price (excluding impact of settled derivatives)			
Oil (Bbl)	$ 48.89	$ 56.57	$ 53.79
Natural gas (Mcf)	2.72	4.49	4.67
Total (Boe)	42.83	50.19	48.47
Average realized sales price (including impact of settled derivatives)			
Oil (Bbl)	$ 48.52	$ 52.87	$ 51.28
Natural gas (Mcf)	2.62	4.51	4.78
Total (Boe)	42.41	47.31	46.62
Additional per Boe data			
Sales price [(b)]	$ 42.83	$ 50.19	$ 48.47
Lease operating expense [(c)]	6.47	5.77	4.84
Gathering and treating expense [(a)]	—	—	0.57
Production taxes	2.51	3.20	2.55
Operating margin	$ 33.85	$ 41.22	$ 40.51
Depletion, depreciation and amortization	$ 15.74	$ 15.02	$ 14.98
Adjusted G&A [(d)]			
Cash component [(e)]	$ 2.03	$ 2.17	$ 2.46
Non-cash component	0.50	0.57	0.54

(a) On January 1, 2018, the Company adopted the revenue recognition accounting standard. Consequently, natural gas gathering and treating expenses for the three and twelve months ended December 31, 2018 were accounted for as a reduction to revenue.
(b) Excludes the impact of settled derivatives.
(c) Excludes gathering and treating expense.

(d) Excludes certain non-recurring expenses and non-cash valuation adjustments. Adjusted G&A is a non-GAAP financial measure; see the reconciliation provided within this press release for a reconciliation of G&A expense on a GAAP basis to Adjusted G&A expense.
(e) Excludes the amortization of equity-settled share-based incentive awards and corporate depreciation and amortization.

Total Revenue. For the quarter ended December 31, 2018, Callon reported total revenue of $161.9 million and total revenue including settled derivatives ("Adjusted Total Revenue," a non-GAAP financial measure[(i)]) of $160.3 million, including the impact of a $1.6 million loss from the settlement of derivative contracts. The table above reconciles Adjusted Total Revenue to the related GAAP measure of the Company's total operating revenue. Average daily production for the quarter was 41.1 Mboe/d compared to average daily production of 34.9 Mboe/d in the third quarter of 2018. Average realized prices, including and excluding the effects of hedging, are detailed above.

Hedging impacts. For the quarter ended December 31, 2018, Callon recognized the following hedging-related items (in thousands, except per unit data):

	Three Months Ended December 31, 2018	
	In Thousands	**Per Unit**
Oil derivatives		
Net loss on settlements	$ (1,157)	$ (0.37)
Net gain on fair value adjustments	101,693	
Total gain on oil derivatives	$ 100,536	
Natural gas derivatives		
Net loss on settlements	$ (437)	$ (0.10)
Net gain on fair value adjustments	3,819	
Total gain on natural gas derivatives	$ 3,382	
Total oil & natural gas derivatives		
Net loss on settlements	$ (1,594)	$ (0.42)
Net gain on fair value adjustments	105,512	
Total gain on total oil & natural gas derivatives	$ 103,918	

Lease Operating Expenses, including workover ("LOE"). LOE per Boe for the three months ended December 31, 2018 was $6.47 per Boe, compared to LOE of $5.77 per Boe in the third quarter of 2018. The increase in this metric resulted primarily from an increase in costs associated with recently acquired assets that reflect a higher historical operating cost.

Production Taxes, including ad valorem taxes. Production taxes were $2.51 per Boe for the three months ended December 31, 2018, representing approximately 6% of total revenue before the impact of derivative settlements.

Depreciation, Depletion and Amortization ("DD&A"). DD&A for the three months ended December 31, 2018 was $15.74 per Boe compared to $15.02 per Boe in the third quarter of 2018. The increase on a per unit basis was primarily attributable to greater increases in our depreciable asset base and assumed future development costs related to undeveloped proved reserves as compared to the estimated total proved reserve base.

General and Administrative ("G&A"). G&A, excluding certain non-cash incentive share-based compensation valuation adjustments, ("Adjusted G&A", a non-GAAP measure[(i)]) was $9.6 million, or $2.53 per Boe, for the three months ended December 31, 2018 compared to $8.8 million, or $2.74 per Boe, for the third quarter of 2018. The cash component of Adjusted G&A was $7.7 million, or $2.03 per Boe, for the three months ended December 31, 2018 compared to $7.0 million, or $2.17 per Boe, for the third quarter of 2018.

For the three months ended December 31, 2018, G&A and Adjusted G&A, which excludes the amortization of equity-settled, share-based incentive awards and corporate depreciation and amortization, are calculated as follows (in thousands):

	Three Months Ended December 31, 2018
Total G&A expense	$ 8,514
Change in the fair value of liability share-based awards (non-cash)	1,069
Adjusted G&A – total	9,583
Restricted stock share-based compensation (non-cash)	(1,802)
Corporate depreciation & amortization (non-cash)	(94)
Adjusted G&A – cash component	$ 7,687

Income tax expense. Callon provides for income taxes at a statutory rate of 21% adjusted for permanent differences expected to be realized, which primarily relate to non-deductible executive compensation expenses, restricted stock windfalls and shortfalls, and state income taxes. We recorded an income tax expense of $5.6 million for the three months ended December 31, 2018 which relates to deferred federal and State of Texas gross margin tax. As of December 31, 2017, the valuation allowance was $60,919. During 2018, the Company's tax position transitioned from a net deferred tax asset position to a net deferred tax liability position, thereby unwinding the valuation allowance balance to $0 as of December 31, 2018. Adjusted Income per fully diluted common share, a non-GAAP financial measure[(i)], adjusts our income (loss) available to common stockholders to reflect our theoretical tax provision of $30.3 million (or $0.13 per diluted share) for the quarter as if the valuation allowance did not exist.

Proved Reserves

DeGolyer and MacNaughton prepared estimates of Callon's reserves as of December 31, 2018.

As of December 31, 2018, our estimated net proved reserves grew 74% from prior year-end, totaling 238.5 MMboe and included 180.1 MMBbls of oil and 350.5 Bcf of natural gas with a standardized measure of discounted future net cash flows of $2.9 billion. Oil constituted approximately 76% of our total estimated equivalent net proved reserves and approximately 72% of our total estimated equivalent proved developed reserves. We added 85.0 MMboe of new reserves in extensions and discoveries through our development efforts in our operating areas, where we drilled a total of 70 gross (57.5 net) wells. We purchased reserves in place of 39.7 MMboe in a significant Delaware acquisition as well as bolt-on acquisitions completed within the Permian Basin and reduced our estimated net proved reserves through net revisions of previous estimates of 2.0 MMboe and reclassifications of 9.1 MMboe to probable reserves. Our net revisions of previous estimates were primarily related to technical revisions of proved undeveloped reserves. We reclassified 19 proved undeveloped ("PUD") locations to probable reserves, primarily due to acreage trades and changes in our development plan, including larger pad development concepts and co-development of zones. These changes resulted in the anticipated drilling of PUD locations being moved beyond five years from initial booking. The changes in our proved reserves are as follows (in Mboe):

Proved reserves:	
Reserves at December 31, 2017	136,974
Extensions and discoveries	84,955
Purchase of reserves in place	39,683
Revisions to previous estimates	(2,021)

Reclassifications due to changes in development plan	(9,065)
Production	(12,018)
Reserves at December 31, 2018	238,508

Callon replaced 690% of 2018 production as calculated by the sum of reserve extensions and discoveries, divided by annual production ("Organic reserve replacement ratio," a non-GAAP financial measure(i)). The Company's finding and development costs from extensions and discoveries ("Drill-bit F&D costs per Boe," a non-GAAP financial measure(i)) were $7.03 per Boe calculated as accrual costs incurred for exploration and development divided by the reserves (in barrels of oil equivalent) added from extensions and discoveries. In addition, the Company had proved developed finding and development costs ("PD F&D costs per Boe," a non-GAAP financial measure(i)) of $13.40 per Boe.

Senior Management Promotions

As part of Callon's focus on leadership development to support the execution of our strategy, Michol Ecklund has been promoted to the role Senior Vice President, General Counsel and Corporate Secretary. In this new role, Michol will leverage her prior experience in human resources, environmental, social and governance (ESG) matters, and philanthropy, while continuing to provide legal advice to Callon. In addition, Liam Kelly has been promoted to the role of Vice President of Corporate Development, continuing to lead our business development efforts as well as manage our corporate planning team.

2019 Guidance

	Full Year 2018 Actual	Full Year 2019 Guidance
Total production (Mboe/d)	32.9	39.5 - 41.5
% oil	79%	77% - 78%
Income statement expenses (per Boe)		
LOE, including workovers	$5.76	$5.50 - $6.50
Production taxes, including ad valorem (% unhedged revenue)	6%	7%
Adjusted G&A: cash component (a)	$2.35	$2.00 - $2.50
Adjusted G&A: non-cash component (b)	$0.55	$0.50 - $1.00
Cash interest expense (c)	$0.00	$0.00
Effective income tax rate	22%	22%
Capital expenditures ($MM, accrual basis)		
Total operational (d)	$583	$500 - $525
Capitalized interest and G&A expenses	$84	$100 - $105
Net operated horizontal wells placed on production	54	47 - 49

(a) Excludes stock-based compensation and corporate depreciation and amortization. Adjusted G&A is a non-GAAP financial measure; see the reconciliation provided within this press release for a reconciliation of G&A expense on a GAAP basis to Adjusted G&A expense.
(b) Excludes certain non-recurring expenses and non-cash valuation adjustments. Adjusted G&A is a non-GAAP financial measure; see the reconciliation provided within this press release for a reconciliation of G&A expense on a GAAP basis to Adjusted G&A expense.
(c) All interest expense anticipated to be capitalized.
(d) Includes facilities, equipment, seismic, land and other items. Excludes capitalized expenses.

Hedge Portfolio Summary

The following table summarizes our open derivative positions as of December 31, 2018 for the periods indicated:

	For the Full Year of	For the Full Year of

Oil contracts (WTI)	2019	2020
Puts		
Total volume (Bbls)	912,500	—
Weighted average price per Bbl	$ 65.00	$ —
Put spreads		
Total volume (Bbls)	912,500	—
Weighted average price per Bbl		
Floor (long put)	$ 65.00	$ —
Floor (short put)	$ 42.50	$ —
Collar contracts combined with short puts (three-way collars)		
Total volume (Bbls)	4,564,000	—
Weighted average price per Bbl		
Ceiling (short call)	$ 67.62	$ —
Floor (long put)	$ 56.60	$ —
Floor (short put)	$ 43.60	$ —
Oil contracts (Midland basis differential)		
Swap contracts		
Total volume (Bbls)	4,746,500	4,024,000
Weighted average price per Bbl	$ (4.72)	$ (1.51)
Natural gas contracts (Henry Hub)		
Collar contracts (two-way collars)		
Total volume (MMBtu)	8,282,500	—
Weighted average price per MMBtu		
Ceiling (short call)	$ 3.46	$ —
Floor (long put)	$ 2.91	$ —
Natural gas contracts (Waha basis differential)		
Swap contracts		
Total volume (MMBtu)	11,321,000	4,758,000
Weighted average price per MMBtu	$ (1.23)	$ (1.12)

Income (Loss) Available to Common Shareholders. The Company reported net income available to common shareholders of $154.4 million for the three months ended December 31, 2018 and Adjusted Income available to common shareholders of $39.9 million, or $0.17 per diluted share. Adjusted Income per fully diluted common share, a non-GAAP financial measure(i), adjusts our income available to common stockholders to reflect our theoretical tax provision for the quarter as if the valuation allowance did not exist. The following tables reconcile to the related GAAP measure the Company's income available to common stockholders to Adjusted Income and the Company's net income to Adjusted EBITDA (in thousands):

	Three Months Ended		
Adjusted Income per fully diluted common share:	**December 31, 2018**	**September 30, 2018**	**December 31, 2017**
Income available to common stockholders	$ 154,370	$ 36,108	$ 21,001
Net (gain) loss on derivatives, net of settlements	(105,512)	25,100	26,037
Change in the fair value of liability share-based awards	(1,053)	879	865
Tax effect on adjustments above	22,379	(5,456)	(9,416)
Change in valuation allowance	(30,281)	(8,323)	(8,285)
Adjusted Income	$ 39,903	$ 48,308	$ 30,202
Adjusted Income per fully diluted common share	$ 0.17	$ 0.21	$ 0.15

	Three Months Ended		
Adjusted EBITDA:	**December 31, 2018**	**September 30, 2018**	**December 31, 2017**
Net income	$ 156,194	$ 37,931	$ 22,824
Net (gain) loss on derivatives, net of settlements	(105,512)	25,100	26,037
Non-cash stock-based compensation expense	770	2,587	2,101
Acquisition expense	1,333	1,435	(112)
Income tax expense	5,647	1,487	248

Interest expense	735	711	461
Depreciation, depletion and amortization	60,301	48,977	37,222
Accretion expense	248	202	154
Adjusted EBITDA	$ 119,716	$ 118,430	$ 88,935

Discretionary Cash Flow. Discretionary cash flow, a non-GAAP measure(i), for the three months ended December 31, 2018 was $118.3 million and is reconciled to operating cash flow in the following table (in thousands):

	Three Months Ended		
	December 31, 2018	**September 30, 2018**	**December 31, 2017**
Cash flows from operating activities:			
Net income	$ 156,194	$ 37,931	$ 22,824
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation, depletion and amortization	60,301	48,977	37,222
Accretion expense	248	202	154
Amortization of non-cash debt related items	734	708	455
Deferred income tax expense	5,647	1,487	247
(Gain) loss on derivatives, net of settlements	(105,512)	25,100	26,037
Gain on sale of other property and equipment	(64)	(102)	—
Non-cash expense related to equity share-based awards	1,823	1,708	1,240
Change in the fair value of liability share-based awards	(1,053)	879	865
Discretionary cash flow	$ 118,318	$ 116,890	$ 89,044
Changes in working capital	33,710	(347)	$ (8,642)
Payments to settle asset retirement obligations	(389)	(507)	(216)
Net cash provided by operating activities	$ 151,639	$ 116,036	$ 80,186

PV-10: Pre-tax PV-10, a non-GAAP measure(i), as of December 31, 2018 is reconciled below to the standardized measure of discounted future net cash flows (in thousands):

	As of December 31, 2018
Standardized measure of discounted future net cash flows	$ 2,941,293
Add: 10 percent annual discount, net of income taxes	3,716,571
Add: future undiscounted income taxes	782,470
Undiscounted future net cash flows	7,440,334
Less: 10 percent annual discount without tax effect	(4,291,127)
Total Proved Reserves - Pre-tax PV-10	3,149,207
Total Proved Developed Reserves - Pre-tax PV-10	2,222,049
Total Proved Undeveloped Reserves - Pre-tax PV-10	$ 927,158

F&D and Reserve Replacement: The following table reconciles Drill-bit finding and development costs per boe(i) ("Drill-bit F&D per boe), Proved Developed finding and developed costs per boe(i) (PD F&D), Organic Reserve Replacement Ratio(i), and All-sources reserve replacement ratio(i); all of which are non-GAAP measures:

	Calculation Parameters	**2018 Metrics**
Production (Mboe)	(A)	12,018
Proved reserve data		
Proved reserves (Mboe)		
Total Proved extensions, discoveries, and other additions	(B)	84,955
Proved Undeveloped extensions, discoveries, and other additions, net of revisions	(C)	52,526
Proved Undeveloped transfers to Proved Developed	(D)	11,075
Total Proved additions, net of revisions and reclassifications	(E)	113,552
Total Proved extensions, discoveries, and other additions, net of revisions	(F)	82,934
Costs Incurred:		
Acquisition costs:		

Evaluated properties		$ 347,305
Unevaluated properties		466,816
Development costs	(G)	259,410
Exploration costs	(H)	323,458
Total costs incurred		$ 1,396,989
Drill-bit F&D costs per Boe (two-stream)	(G + H) / (F)	$7.03
PD F&D per Boe (two-stream)	(G + H) / (B - C + D)	$13.40
Organic reserve replacement ratio	(F) / (A)	690%
All-sources reserve replacement ratio	(E) / (A)	945%

Callon Petroleum Company
Consolidated Balance Sheets
(in thousands, except par and per share values and share data)

	December 31, 2018	December 31, 2017
ASSETS		
Current assets:		
Cash and cash equivalents	$ 16,051	$ 27,995
Accounts receivable	131,720	114,320
Fair value of derivatives	65,114	406
Other current assets	9,740	2,139
Total current assets	222,625	144,860
Oil and natural gas properties, full cost accounting method:		
Evaluated properties	4,585,020	3,429,570
Less accumulated depreciation, depletion, amortization and impairment	(2,270,675)	(2,084,095)
Net evaluated oil and natural gas properties	2,314,345	1,345,475
Unevaluated properties	1,404,513	1,168,016
Total oil and natural gas properties, net	3,718,858	2,513,491
Other property and equipment, net	21,901	20,361
Restricted investments	3,424	3,372
Deferred tax asset	—	52
Deferred financing costs	6,087	4,863
Acquisition deposit	—	900
Other assets, net	6,278	5,397
Total assets	$ 3,979,173	$ 2,693,296
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 261,184	$ 162,878
Accrued interest	24,665	9,235
Cash-settleable restricted stock unit awards	1,390	4,621
Asset retirement obligations	3,887	1,295
Fair value of derivatives	10,480	27,744
Other current liabilities	13,310	—
Total current liabilities	314,916	205,773
Senior secured revolving credit facility	200,000	25,000
6.125% senior unsecured notes due 2024	595,788	595,196
6.375% senior unsecured notes due 2026	393,685	—
Asset retirement obligations	10,405	4,725
Cash-settleable restricted stock unit awards	2,067	3,490
Deferred tax liability	9,564	1,457
Fair value of derivatives	7,440	1,284
Other long-term liabilities	100	405
Total liabilities	1,533,965	837,330
Commitments and contingencies		
Stockholders' equity:		
Preferred stock, series A cumulative, $0.01 par value and $50.00 liquidation preference, 2,500,000 shares authorized: 1,458,948 shares outstanding	15	15
Common stock, $0.01 par value, 300,000,000 shares authorized; 227,582,575 and 201,836,172 shares outstanding, respectively	2,276	2,018
Capital in excess of par value	2,477,278	2,181,359
Accumulated deficit	(34,361)	(327,426)

Total stockholders' equity	2,445,208	1,855,966
Total liabilities and stockholders' equity	$ 3,979,173	$ 2,693,296

Callon Petroleum Company
Consolidated Statements of Operations
(in thousands, except per share data)

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2018	**2017**	**2018**	**2017**
Operating revenues:				
Oil sales	$ 150,398	$ 104,132	$ 530,898	$ 322,374
Natural gas sales	11,497	14,082	56,726	44,100
Total operating revenues	161,895	118,214	587,624	366,474
Operating expenses:				
Lease operating expenses	24,475	13,201	69,180	49,907
Production taxes	9,490	6,228	35,755	22,396
Depreciation, depletion and amortization	59,502	36,543	181,909	115,714
General and administrative	8,514	8,172	35,293	27,067
Settled share-based awards	—	—	—	6,351
Accretion expense	248	154	874	677
Acquisition expense	1,333	(112)	5,083	2,916
Total operating expenses	103,562	64,186	328,094	225,028
Income from operations	58,333	54,028	259,530	141,446
Other (income) expenses:				
Interest expense, net of capitalized amounts	735	461	2,500	2,159
(Gain) loss on derivative contracts	(103,918)	30,536	(48,544)	18,901
Other income	(325)	(41)	(2,896)	(1,311)
Total other (income) expense	(103,508)	30,956	(48,940)	19,749
Income before income taxes	161,841	23,072	308,470	121,697
Income tax (benefit) expense	5,647	248	8,110	1,273
Net income	156,194	22,824	300,360	120,424
Preferred stock dividends	(1,824)	(1,823)	(7,295)	(7,295)
Income available to common stockholders	$ 154,370	$ 21,001	$ 293,065	$ 113,129
Income per common share:				
Basic	$ 0.68	$ 0.10	$ 1.35	$ 0.56
Diluted	$ 0.68	$ 0.10	$ 1.35	$ 0.56
Shares used in computing income per common share:				
Basic	227,580	201,835	216,941	201,526
Diluted	228,191	202,426	217,596	202,102

Callon Petroleum Company
Consolidated Statements of Cash Flows
(in thousands)

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2018	**2017**	**2018**	**2017**
Cash flows from operating activities:				
Net income (loss)	$ 156,194	$ 22,824	$ 300,360	$ 120,424
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion and amortization	60,301	37,222	184,731	118,051
Accretion expense	248	154	874	677
Amortization of non-cash debt related items	734	455	2,483	2,150
Deferred income tax (benefit) expense	5,647	247	8,110	1,273
Net (gain) loss on derivatives, net of settlements	(105,512)	26,037	(75,816)	10,429
(Gain) loss on sale of other property and equipment	(64)	—	(144)	62
Non-cash expense related to equity share-based awards	1,823	1,240	6,289	8,254
Change in the fair value of liability share-based awards	(1,053)	865	375	3,288
Payments to settle asset retirement obligations	(389)	(216)	(1,469)	(2,047)
Payments for cash-settled restricted stock unit awards	—	—	(4,990)	(13,173)
Changes in current assets and liabilities:				

Accounts receivable	37,033	(32,347)	(17,351)	(44,495)
Other current assets	(5,936)	444	(7,601)	108
Current liabilities	9,510	23,413	74,311	30,947
Other long-term liabilities	(6,065)	—	(278)	121
Other assets, net	(832)	(152)	(2,230)	(1,528)
Other	—	—	—	(4,650)
Net cash provided by operating activities	151,639	80,186	467,654	229,891
Cash flows from investing activities:				
Capital expenditures	(155,821)	(152,621)	(611,173)	(419,839)
Acquisitions	(122,809)	(3,952)	(718,793)	(718,456)
Acquisition deposit	—	(900)	—	45,238
Proceeds from sales of assets	683	20,525	9,009	20,525
Additions to other assets	(3,100)	—	(3,100)	—
Net cash used in investing activities	(281,047)	(136,948)	(1,324,057)	(1,072,532)
Cash flows from financing activities:				
Borrowings on senior secured revolving credit facility	230,000	25,000	500,000	25,000
Payments on senior secured revolving credit facility	(95,000)	—	(325,000)	—
Issuance of 6.125% senior unsecured notes due 2024	—	—	—	200,000
Premium on the issuance of 6.125% senior unsecured notes due 2024	—	—	—	8,250
Issuance of 6.375% senior unsecured notes due 2026	—	—	400,000	—
Payment of deferred financing costs	530	(28)	(9,430)	(7,194)
Issuance of common stock	(376)	—	287,988	—
Payment of preferred stock dividends	(1,824)	(1,824)	(7,295)	(7,295)
Tax withholdings related to restricted stock units	—	—	(1,804)	(1,118)
Net cash provided by financing activities	133,330	23,148	844,459	217,643
Net change in cash and cash equivalents	3,922	(33,614)	(11,944)	(624,998)
Balance, beginning of period	12,129	61,609	27,995	652,993
Balance, end of period	16,051	27,995	$ 16,051	$ 27,995

Non-GAAP Financial Measures and Reconciliations

This news release refers to non-GAAP financial measures such as "Discretionary Cash Flow," "Adjusted G&A," "Adjusted Income," "Adjusted EBITDA" and "Adjusted Total Revenue." These measures, detailed below, are 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 (including the notes), included in our SEC filings and posted on our website.

- Callon believes that the non-GAAP measure of discretionary cash flow is a comparable metric against other companies in the industry and is a widely accepted financial indicator of an oil and natural gas company's ability to generate cash for the use of internally funding their capital development program and to service or incur debt. Discretionary cash flow is defined by Callon as net cash provided by operating activities before changes in working capital and payments to settle asset retirement obligations and vested liability share-based awards. Callon has included this information because changes in operating assets and liabilities relate to the timing of cash receipts and disbursements, which the Company may not control and the cash flow effect may not be reflected the period in which the operating activities occurred. Discretionary cash flow is not a measure of a company's financial performance under GAAP and should not be considered as an alternative to net cash provided by operating activities (as defined under GAAP), or as a measure of liquidity, or as an alternative to net income.
- Adjusted general and administrative expense ("Adjusted G&A") is a supplemental non-GAAP financial measure that excludes certain non-recurring expenses and non-cash valuation adjustments related to incentive compensation plans, as well as non-cash corporate depreciation and amortization expense. Callon believes that the non-GAAP measure of Adjusted G&A is useful to investors because it provides readers with a

meaningful measure of our recurring G&A expense and provides for greater comparability period-over-period. The table here within details all adjustments to G&A on a GAAP basis to arrive at Adjusted G&A.

- Callon believes that the non-GAAP measure of Adjusted Income available to common shareholders ("Adjusted Income") and Adjusted Income per diluted share are useful to investors because they provide readers with a meaningful measure of our profitability before recording certain items whose timing or amount cannot be reasonably determined. These measures exclude the net of tax effects of certain non-recurring items and non-cash valuation adjustments, which are detailed in the reconciliation provided here within.
- Callon calculates adjusted earnings before interest, income taxes, depreciation, depletion and amortization ("Adjusted EBITDA") as Adjusted Income plus interest expense, income tax expense (benefit) and depreciation, depletion and amortization expense. Adjusted EBITDA is not a measure of financial performance under GAAP. Accordingly, it should not be considered as a substitute for net income (loss), operating income (loss), cash flow provided by operating activities or other income or cash flow data prepared in accordance with GAAP. However, the Company believes that Adjusted EBITDA provides additional information with respect to our performance or ability to meet our future debt service, capital expenditures and working capital requirements. Because Adjusted EBITDA excludes some, but not all, items that affect net income (loss) and may vary among companies, the Adjusted EBITDA presented may not be comparable to similarly titled measures of other companies.
- Callon believes that the non-GAAP measure of Adjusted Total Revenue is useful to investors because it provides readers with a revenue value more comparable to other companies who engage in price risk management activities through the use of commodity derivative instruments and reflects the results of derivative settlements with expected cash flow impacts within total revenues.
- We believe "Drill-Bit F&D costs per Boe," "PD F&D costs per Boe", "Organic reserve replacement ratio", and "All-sources reserve replacement ratio" are non-GAAP metrics commonly used by Callon and other companies in our industry, as well as analysts and investors, to measure and evaluate the cost of replenishing annual production and adding proved reserves. The Company's definitions of "Drill-Bit F&D costs per Boe," "PD F&D costs per Boe" and "Organic reserve replacement ratio" and "All-sources reserve replacement ratio" may differ significantly from definitions used by other companies to compute similar measures and as a result may not be comparable to similar measures provided by other companies. Consequently, we provided the detail of our calculation within the included tables.
- Year-end pre-tax PV-10 value is a non-GAAP financial measure as defined by the SEC. Callon believes that the presentation of pre-tax PV-10 value is relevant and useful to its investors because it presents the discounted future net cash flows attributable to reserves prior to taking into account future corporate income taxes and the Company's current tax structure. The Company further believes investors and creditors use pre-tax PV-10 values as a basis for comparison of the relative size and value of its reserves as compared with other companies. The GAAP financial measure most directly comparable to pre-tax PV-10 is the standardized measure of discounted future net cash flows ("Standardized Measure"). Pre-tax PV-10 is calculated using the Standardized Measure before deducting future income taxes, discounted at 10 percent. The 12-month average benchmark pricing used to estimate proved reserves in accordance with the definitions and regulations of the U.S. Securities and Exchange

Commission ("SEC") and pre-tax PV-10 value for crude oil and natural gas was $65.56 per Bbl of WTI crude oil and $3.10 per MMBtu of natural gas at Henry Hub before differential adjustments. After differential adjustments, the Company's SEC pricing realizations for year-end 2018 were $58.40 per Bbl of oil and $3.64 per Mcf of natural gas.

Earnings Call Information

The Company will host a conference call on Wednesday, February 27, 2019, to discuss fourth quarter 2018 financial and operating results.

Please join Callon Petroleum Company via the Internet for a webcast of the conference call:

Date/Time:	Wednesday, February 27, 2019, at 8:00 a.m. Central Time (9:00 a.m. Eastern Time)
Webcast:	Select "IR Calendar" under the "Investors" section of the Company's website: www.callon.com.

Alternatively, you may join by telephone using the following numbers:

Domestic:	1-888-317-6003
Canada:	1-866-284-3684
International:	1-412-317-6061
Access code:	6127927

An archive of the conference call webcast will also be available atwww.callon.com under the "Investors" section of the website.

About Callon Petroleum

Callon Petroleum Company is an independent energy company focused on the acquisition, development, exploration, and operation of oil and natural gas properties in the Permian Basin in West Texas.

Cautionary Statement Regarding Forward Looking Statements

This news release contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements include all statements regarding wells anticipated to be drilled and placed on production; future levels of drilling activity and associated production and cash flow expectations; the Company's 2019 production guidance and capital expenditure forecast; estimated reserve quantities and the present value thereof; and the implementation of the Company's business plans and strategy, as well as statements including the words "believe," "expect," "plans", "may", "will", "should", "could" and words of similar meaning. These statements reflect the Company's current views with respect to future events and financial performance based on management's experience and perception of historical trends, current conditions, anticipated future developments and other factors believed to be appropriate. No assurances can be given, however, that these events will occur or that these projections will be achieved, and actual results could differ materially from those projected as a result of certain factors. Any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law. Some of the factors which could affect our future results and could cause results to differ materially from those expressed in our forward-looking statements include the volatility of oil and natural gas prices, ability to drill and complete wells, operational, regulatory and environment risks, cost and availability of equipment and labor, our ability to finance our activities and other risks more fully discussed in our filings with the Securities and Exchange Commission, including our Annual Reports on Form 10-K and Quarterly Reports on Form 10-Q, available on our website or the SEC's website at www.sec.gov.

Contact information

Mark Brewer
Director of Investor Relations
Callon Petroleum Company
ir@callon.com
1-281-589-5200

(i) See "Non-GAAP Financial Measures and Reconciliations" included within this release for related disclosures and calculations