Callon Petroleum Company Announces Third Quarter 2016 Results

Natchez, MS (November 2, 2016) - Callon Petroleum Company (NYSE: CPE) ("Callon" or the "Company") today reported results of operations for the three months ended September 30, 2016.

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.

Financial and operational highlights for the third quarter of 2016 and other recent data points include:

- Net daily production of 16,598 barrels of oil equivalent per day ("BOE/d"), an increase of 23% compared to the second quarter of 2016
- GAAP income per diluted common share of $0.14 and Adjusted Income per fully diluted common share, a non-GAAP financial measure[i], of $0.09
- Closed the Plymouth Acquisition and related common stock financing, expanding our WildHorse area footprint to over 20,000 net acres and total Midland Basin acreage to over 40,000 net acres
- Continued strong performance from our initial Wolfcamp A completion in Howard County (Silver City Unit A 01H), with cumulative production of over 192,000 BOE (89% oil) in the first 110 days on production
- Commenced program development of the WildHorse area with a two-well pad targeting both the Wolfcamp A and Lower Spraberry zones in northwest Howard County
- Refinanced our Term Loan with the issuance of Senior Notes, reducing our cost of capital and establishing a benchmark, publicly-traded security for future financing opportunities
- Raised 2016 full year production guidance to a range of 15,250 – 15,550 BOE/d and reaffirmed operational capital guidance for 2016 of $140 million

"Our strong recent well results combined with the longer term performance of our production base enable us to continue our track record of sustained production growth within a restrained capital program," commented Fred Callon, Chairman and Chief Executive Officer. "Given our expanded portfolio of drilling opportunities that deliver solid returns on investment at less than $50 per barrel of oil, combined with low leverage metrics and liquidity of almost $500 million, we currently anticipate adding a third horizontal drilling rig in early 2017 and are preparing for a fourth rig in the second half of 2017. We forecast this program would deliver approximately 30,000 BOE/d of annual average production in 2018, while generating free cash flow by mid-year 2018 based on our 2018 planning case assumptions of $50 per barrel and a theoretical increase of 15% in completed well costs to address the impact of evolving completion designs and potential upward pressure on service costs from anticipated increases in core Permian Basin activity."

Operations Update

At September 30, 2016, we had 124 gross (98.0 net) horizontal wells producing from six established flow units. Net daily production for the three months ended September 30, 2016 grew approximately 70% to 16,598 BOE/d (approximately 76% oil) as compared to the same period of 2015. Sequentially, we grew production more than 23% compared to the second quarter of 2016.

For the three months ended September 30, 2016, we operated 1.6 horizontal drilling rigs, drilled 8 gross (5.4 net) horizontal wells, completed 11 gross (6.8 net) horizontal wells, and placed 7 gross (5.2 net) horizontal wells on production. As of September 30, 2016, we had 3 gross (2.8 net) horizontal wells awaiting completion.

Well Activity Summary

The following table details well-related activity for the quarter by focus area:

	For the Three Months Ended September 30, 2016							
	Drilled		Completed		Placed on Production		Awaiting Completion	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
WildHorse	—	—	—	—	1	1.0	—	—
Monarch	8	5.4	9	5.7	4	3.1	3	2.8
Ranger	—	—	2	1.1	2	1.1	—	—
Total	8	5.4	11	6.8	7	5.2	3	2.8

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

During the third quarter, we continued to focus on development of two flow units within the Lower Spraberry in the Monarch area while also progressing the infrastructure buildout of WildHorse in preparation for program development with multi-well pads. The following table highlights wells that achieved peak rates during the period:

				24-Hour Peak IP (BOE/d; Two-stream) [a]			30-Day Average Peak IP (BOE/d; Two-stream)		
24-Hour IP Date	**Well**	**Focus Area (Zone)**	**Completed Lateral (ft)**	**Peak 24-Hour IP**	**Production (% oil)**	**Per 1,000' Lateral Feet**	**Peak 30-Day IP**	**Production (% oil)**	**Per 1,000' Lateral Feet**
07/10/2016	Kendra-Annie 11 22SH	Monarch (LS)	7,917	919	89%	116	894	88%	113
07/07/2016	Pecan Acres 22A4 11SH	Monarch (LS)	4,622	719	87%	155	768	87%	166
08/03/2016	Silver City Unit A 01H	WildHorse (WCA)	7,363	2,459	91%	334	2,148	89%	292

(a) 24-Hour Peak IPs correspond to the rates filed with the Railroad Commission of Texas and are captured using well tests on the specified date, which may result in an understated rate as the production typically varies more widely during the early days of production. The 30-Day Average Peak IP is calculated using allocated production, and is occasionally greater than the reported 24-Hour Peak IP if the well test on that date captured a lower rate than the average for the period.

In early October, our first Wolfcamp A well in the Monarch area was placed on production in the Pecan Acres field in close proximity to recent offsetting industry activity in this zone. The Wolfcamp A represents our fifth producing flow unit in the Monarch area, inclusive of the upper and lower benches of the Lower Spraberry, the Middle Spraberry and the Wolfcamp B. This well was drilled from a stacked two-well pad with a Lower Spraberry (upper bench) well. Both wells are cleaning up and have not reached peak rates.

We also completed two drilled, uncompleted wells in the Ranger area that were acquired earlier this year as part of our AMI transaction in western Reagan County. Our development activity in the Ranger area had previously been focused on Lower Wolfcamp B, and these wells expand our efforts to the Upper Wolfcamp B and Wolfcamp A. Importantly, we utilized a new generation completion design on these latest wells, with proppant loading approximating 2,000 pounds per foot combined with tighter stage spacing. Both wells were placed online in late September and have not reached peak rates.

Our first operated completion in the WildHorse area yielded encouraging results with the Silver City Unit A 01H well achieving 24-Hour and 30-Day IP rates of 334 (91% oil) and 292 (89% oil) BOE/d per 1,000 feet of completed lateral, respectively. This Wolfcamp A well has produced over 192 MBOE in the first 110 days since first production. As part of our newly initiated program development of WildHorse, we recently finished drilling two wells in offsetting acreage targeting both the Wolfcamp A and Lower Spraberry zones from a two-well pad. The rig remains active on this acreage, currently drilling two additional wells targeting both the Wolfcamp A and Lower Spraberry zones from a stacked two-well pad.

Capital Expenditures

For the three months ended September 30, 2016, we accrued $43.3 million in operational capital expenditures, including facilities expenditures of $4.5 million, compared to $21.1 million in the second quarter of 2016. Total capital expenditures, inclusive of capitalized expenses, are detailed below on an accrual and cash basis (in thousands):

	Three Months Ended September 30, 2016				
	Operational Capital	**Seismic & Other**	**Capitalized Interest**	**Capitalized G&A**	**Total Capital Expenditures**
Cash basis [a]	$ 30,182	$ 7,258	$ 7,133	$ 2,845	$ 47,418
Timing adjustments [b]	13,127	(535)	112	—	12,704
Non-cash items	—	—	—	3,217	3,217
Accrual (GAAP) basis	$ 43,309	$ 6,723	$ 7,245	$ 6,062	$ 63,339

(a) Cash basis is a non-GAAP measure that we believe helps users of the financial information reconcile amounts to the cash flow statement and to account for timing related operational changes such as our development pace and rig count.
(b) Includes timing adjustments related to cash disbursements in the current period for capital expenditures incurred in the prior period.

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

Operating and Financial Results

The following table presents summary information for the periods indicated:

	Three Months Ended		
	September 30, 2016	June 30, 2016	September 30, 2015
Net production:			
Oil (MBbls)	1,153	948	689
Natural gas (MMcf)	2,244	1,658	1,239
Total production (MBOE)	1,527	1,224	896
Average daily production (BOE/d)	16,598	13,451	9,739
% oil (BOE basis)	76%	77%	77%
Oil and natural gas revenues (in thousands):			
Oil revenue	$ 49,095	$ 40,555	$ 30,582
Natural gas revenue	6,832	4,590	3,734
Total revenue	$ 55,927	$ 45,145	$ 34,316
Impact of cash-settled derivatives	4,091	4,017	9,789
Adjusted Total Revenue [i]	$ 60,018	$ 49,162	$ 44,105

Total Revenue. For the quarter ended September 30, 2016, Callon reported total revenues of $55.9 million and total revenues including cash-settled derivatives ("Adjusted Total Revenue," a non-GAAP financial measure[i]) of $60 million, including the $4.1 million impact of settled derivative contracts. The table above reconciles to the related GAAP measure of the Company's revenue to Adjusted Total Revenue. Average daily production for the quarter was 16,598 BOE/d compared to average daily production of 13,451 BOE/d in the second quarter of 2016. Average realized prices, including and excluding the effects of hedging, are detailed below.

Hedging impacts. For the quarter ended September 30, 2016, Callon recognized the following hedging-related items (in thousands):

	In Thousands	Per Unit
Oil derivatives contracts		
Net gain on settlements	$ 4,252	$ 3.69
Net gain on fair value adjustments	699	
Total net gain on oil derivatives contracts	$ 4,951	
Natural gas derivatives contracts		
Net loss on settlements	$ (161)	$ (0.07)
Net gain on fair value adjustments	345	
Total net gain on natural gas derivatives contracts	$ 184	
Total derivatives contracts		
Net gain on settlements	$ 4,091	$ 2.67
Net gain on fair value adjustments	1,044	
Total net gain on total derivatives contracts	$ 5,135	

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

Average realized prices, including and excluding the impact of cash settled derivatives during the third quarter, were as follows:

		Three Months Ended September 30, 2016
Average realized sales price		
Oil (per Bbl) (excluding impact of cash-settled derivatives)	$	42.58
Impact of cash-settled derivatives		3.69
Oil (per Bbl) (including impact of cash-settled derivatives)	$	46.27
Natural gas (per Mcf) (excluding impact of cash-settled derivatives)	$	3.04
Impact of cash-settled derivatives		(0.07)
Natural gas (per Mcf) (including impact of cash-settled derivatives)	$	2.97
Total (per BOE) (excluding impact of cash-settled derivatives)	$	36.63
Impact of cash-settled derivatives		2.67
Total (per BOE) (including impact of cash-settled derivatives)	$	39.30

	Three Months Ended					
	September 30, 2016		June 30, 2016		September 30, 2015	
Additional per BOE data:						
Sales price, excluding impact of cash-settled derivatives	$	36.63	$	36.88	$	38.30
Sales price, including impact of cash-settled derivatives		39.30		40.17		49.22
Lease operating expense	$	6.52	$	5.97	$	8.03
Production taxes		2.28		2.01		2.88
Depletion, depreciation and amortization		11.33		13.31		18.64
G&A		5.17		5.15		4.80
Adjusted G&A - total [(a)]		2.96		3.55		4.63
Adjusted G&A - cash component [(b)]		2.38		2.92		3.81

(a) Excludes certain non-recurring expenses and non-cash valuation adjustments. 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 the amortization of equity-settled share-based incentive awards and corporate depreciation and amortization.

Lease Operating Expenses, including workover expense (“LOE”). LOE per BOE for the three months ended September 30, 2016 was $6.52 per BOE, compared to LOE of $5.97 per BOE in the second quarter of 2016. The increase in this metric was primarily related to higher saltwater disposal and fuel and power expenses related to assets acquired during 2016. We continue to make investments in infrastructure in these areas to support our planned increases in drilling activity and expect these investments to reduce our LOE in these areas over time.

Production Taxes, including ad valorem taxes. Production taxes were $2.28 per BOE in the third quarter of 2016, representing approximately 6.2% of total revenue before the impact of derivative settlements.

Depreciation, Depletion and Amortization (“DD&A”). DD&A for the three months ended September 30, 2016 was $11.33 per BOE compared to $13.31 per BOE in the second quarter of 2016. The write-down of our oil and natural gas properties recorded during the second quarter 2016 reduced the amortizable base, while our underlying reserve base continues to increase as we progress our horizontal development program. Combined, these changes resulted in the $1.98 per BOE reduction in DD&A.

General and Administrative (“G&A”). G&A for the third quarter of 2016 was $7.9 million, or $5.17 per BOE, compared to $6.3 million, or $5.15 per BOE, for the second quarter of 2016. G&A, excluding certain non-cash incentive share-based compensation valuation adjustments, (“Adjusted G&A”, a non-GAAP measure[i]) was $4.5 million, or $2.96 per BOE, for the third quarter of 2016 compared to $4.3 million, or $3.55 per BOE, for the second quarter of 2016. The cash component of Adjusted G&A was $3.6 million, or $2.38 per BOE, for the third quarter of 2016 compared to $3.6 million, or $2.92 per BOE, for the second quarter of 2016.

i. See “Non-GAAP Financial Measures and Reconciliations” included within this release for related disclosures and calculations

For the third quarter of 2016, 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):

	Cash	Non-Cash	Total
G&A expenses			
Cash G&A	$ 3,637	$ —	$ 3,637
Restricted stock share-based compensation	—	768	768
Change in the fair value of liability share-based awards	—	3,372	3,372
Corporate depreciation & amortization	—	114	114
Total G&A expense:	$ 3,637	$ 4,254	$ 7,891
Adjusted G&A [(i)]			
Less: Change in the fair value of liability share-based awards			$ (3,372)
Adjusted G&A – total			4,519
Restricted stock share-based compensation			(768)
Corporate depreciation & amortization			(114)
Adjusted G&A – cash component			$ 3,637

Income tax expense. Callon typically provides for income taxes at a statutory rate of 35% adjusted for permanent differences expected to be realized, which primarily relate to non-deductible executive compensation expenses and state income taxes. We recorded $0.1 million income tax expense for the three months ended September 30, 2016. At September 30, 2016 we had a valuation allowance of $139.6 million. 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 for the quarter as if the valuation allowance did not exist.

A breakdown of the Company's anticipated 2016 operational plan and associated expenditures is presented below:

	YTD 2016	Estimated 4th Quarter	Total
Operational activity (gross / net)			
Drilled wells	19 / 13.4	12 / 7.7	31 / 21.1
Completed wells	25 / 17.3	7 / 6.5	32 / 23.8
Wells placed on production	20 / 14.7	10 / 6.5	30 / 21.2
Capital expenditures (in millions, accrual basis)			
Drilling and completion	$ 84.6	$ 31.7	$ 116.3
Facilities	14.7	9.0	23.7
Operational capital expenditures	$ 99.3	$ 40.7	$ 140.0
Seismic	3.4	0.7	4.1
Land and other	5.8	0.3	6.1
Total capital expenditures (excl. capitalized expenses)	$ 108.5	$ 41.7	$ 150.2

2016 Guidance Update

	Previous Full Year 2016 Guidance	Updated Full Year 2016 Guidance
Total production (BOE/d)	14,500 - 15,500	15,250 - 15,550
% oil	76% - 80%	75% - 77%
Expenses (per BOE)		
LOE, including workovers	$5.75 - $6.25	$6.00 - $6.50
Production taxes, including ad valorem (% unhedged revenue)	7%	7%
Adjusted G&A [(a)]	$3.25 - $3.75	$3.15 - $3.40
Adjusted G&A - cash component [(b)]	$2.35 - $2.85	$2.50 - $2.75
Total capital expenditures		
Accrual basis ($MM)	$140	$140

(a) Excludes certain non-recurring expenses and non-cash valuation adjustments. The reconciliation above provides a reconciliation of second quarter 2016 G&A expense on a GAAP basis to Adjusted G&A expense, a non-GAAP measure. The Company is unable to present a quantitative reconciliation of this forward-looking non-GAAP financial measure without unreasonable effort because of the number of estimated variables that could affect the final value. Accordingly, investors are cautioned not to place undue reliance on this information.

(b) Excludes stock-based compensation and corporate depreciation and amortization. See the Non-GAAP related disclosures referenced in the footnote (c) above.

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

Hedge Portfolio Summary

The following table summarizes our open derivative positions as of November 2, 2016:

Oil contracts	For the Remainder of 2016	For the Full Year of 2017
Swap contracts (WTI)		
Total volume (MBbls)	184	—
Weighted average price per Bbl	$ 58.23	$ —
Swap contracts combined with short puts (WTI, enhanced swaps)		
Total volume (MBbls)	—	730
Weighted average price per Bbl		
Swap	$ —	$ 44.50
Short put option	$ —	$ 30.00
Collar contracts combined with short puts (WTI, three-way collars)		
Volume (MBbls)	184	—
Weighted average price per Bbl		
Ceiling (short call option)	$ 65.00	$ —
Floor (long put option)	$ 55.00	$ —
Short put option	$ 40.33	$ —
Collar contracts (WTI, two-way collars)		
Total volume (MBbls)	184	1,533
Weighted average price per Bbl		
Ceiling (short call)	$ 46.50	$ 58.15
Floor (long put)	$ 37.50	$ 47.50
Call option contracts (short position)		
Total volume (MBbls)	—	670
Weighted average price per Bbl		
Call strike price	$ —	$ 50.00
Swap contracts (Midland basis differentials)		
Volume (MBbls)	368	—
Weighted average price per Bbl	$ 0.17	$ —
Natural gas contracts		
Swap contracts (Henry Hub)		
Total volume (BBtu)	552	—
Weighted average price per MMBtu	$ 2.52	$ —
Collar contracts combined with short puts (three-way collars)		
Total volume (BBtu)	—	1,460
Weighted average price per MMBtu		
Ceiling (short call option)	$ —	$ 3.71
Floor (long put option)	$ —	$ 3.00
Short put option	$ —	$ 2.50

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

Income (Loss) Available to Common Shareholders. The Company reported a net income available to common shareholders of $19.3 million in the third quarter of 2016 and Adjusted Income available to common shareholders of $12.9 million, or $0.09 per diluted share. The following tables reconcile to the related GAAP measure the Company's income (loss) available to common stockholders to Adjusted Income and the Company's net income (loss) to Adjusted EBITDA (in thousands):

	Three Months Ended		
	September 30, 2016	**June 30, 2016**	**September 30, 2015**
Income (loss) available to common stockholders	$ 19,315	$ (71,920)	$ (113,779)
Change in valuation allowance	(7,907)	24,409	68,818
Write-down of oil and natural gas properties	—	39,658	56,746
Net loss (gain) on derivatives, net of settlements	(679)	12,676	(8,771)
Change in the fair value of share-based awards	2,192	1,277	37
Withdrawn proxy contest expenses	—	2	65
Adjusted Income	$ 12,921	$ 6,102	$ 3,116
Adjusted Income per fully diluted common share	$ 0.09	$ 0.05	$ 0.05

	Three Months Ended		
	September 30, 2016	**June 30, 2016**	**September 30, 2015**
Net income (loss)	$ 21,139	$ (70,097)	$ (111,805)
Write-down of oil and natural gas properties	—	61,012	87,301
Net loss (gain) on derivatives, net of settlements	(1,044)	19,501	(13,494)
Change in the fair value of share-based awards	4,150	2,628	655
Withdrawn proxy contest expenses	—	3	100
Acquisition expense	456	1,906	(3)
Income tax (benefit) expense	(62)	—	45,667
Interest expense	831	4,180	5,603
Depreciation, depletion and amortization	17,733	16,698	16,026
Accretion expense	187	395	142
Adjusted EBITDA	$ 43,390	$ 36,226	$ 30,192

Discretionary Cash Flow. Discretionary cash flow, a non-GAAP measure[i], for the third quarter of 2016 was $42.7 million and is reconciled to operating cash flow in the following table (in thousands):

	Three Months Ended		
	September 30, 2016	**June 30, 2016**	**September 30, 2015**
Cash flows from operating activities:			
Net income (loss)	**$** 21,139	$ (70,097)	$ (111,805)
Adjustments to reconcile net income (loss) to cash provided by operating activities:			
Depreciation, depletion and amortization	17,733	16,698	16,026
Write-down of oil and natural gas properties	—	61,012	87,301
Accretion expense	187	395	142
Amortization of non-cash debt related items	810	780	781
Deferred income tax expense	(62)	—	45,667
Net loss (gain) on derivatives, net of settlements	(1,044)	19,501	(13,494)
Non-cash expense related to equity share-based awards	608	(1,253)	368
Change in the fair value of liability share-based awards	3,371	1,965	64
Discretionary cash flow	$ 42,742	$ 29,001	$ 25,050
Changes in working capital	2,927	(6,974)	1,639
Acquisition deposit	(32,700)	—	—
Payments to settle asset retirement obligations	(576)	(158)	(1,142)
Payments to settle vested liability share-based awards	—	(493)	—
Net cash provided by operating activities	$ 12,393	$ 21,376	$ 25,547

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

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

	September 30, 2016 Unaudited	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$ 325,885	$ 1,224
Accounts receivable	56,172	39,624
Fair value of derivatives	3,502	19,943
Other current assets	1,712	1,461
Total current assets	387,271	62,252
Oil and natural gas properties, full cost accounting method:		
Evaluated properties	2,593,798	2,335,223
Less accumulated depreciation, depletion, amortization and impairment	(1,901,102)	(1,756,018)
Net oil and natural gas properties	692,696	579,205
Unevaluated properties	393,875	132,181
Total oil and natural gas properties	1,086,571	711,386
Other property and equipment, net	12,816	7,700
Restricted investments	3,329	3,309
Deferred financing costs	3,431	3,642
Fair value of derivatives	57	—
Acquisition deposit	32,700	—
Other assets, net	1,429	305
Total assets	$ 1,527,604	$ 788,594
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 99,026	$ 70,970
Accrued interest	5,950	5,989
Cash-settleable restricted stock unit awards	8,269	10,128
Asset retirement obligations	3,529	790
Deferred tax liability	42	—
Fair value of derivatives	7,786	—
Total current liabilities	124,602	87,877
Senior secured revolving credit facility	—	40,000
Secured second lien term loan, net of unamortized deferred financing costs	290,085	288,565
Asset retirement obligations	1,934	4,317
Cash-settleable restricted stock unit awards	7,042	4,877
Fair value of derivatives	2,936	—
Other long-term liabilities	286	200
Total liabilities	426,885	425,836
Stockholders' equity:		
Preferred stock, series A cumulative, $0.01 par value and $50.00 liquidation preference, 2,500,000 shares authorized: 1,458,948 and 1,578,948 shares outstanding, respectively	15	16
Common stock, $0.01 par value, 300,000,000 and 150,000,000 shares authorized, respectively; 161,036,233 and 80,087,148 shares outstanding, respectively	1,610	801
Capital in excess of par value	1,535,661	702,970
Accumulated deficit	(436,567)	(341,029)
Total stockholders' equity	1,100,719	362,758
Total liabilities and stockholders' equity	$ 1,527,604	$ 788,594

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	**2015**	**2016**	**2015**
Operating revenues:				
Oil sales	$ 49,095	$ 30,582	$ 117,093	$ 94,584
Natural gas sales	6,832	3,734	14,677	9,365
Total operating revenues	55,927	34,316	131,770	103,949
Operating expenses:				
Lease operating expenses	9,961	7,194	24,229	20,728
Production taxes	3,478	2,583	8,153	7,800
Depreciation, depletion and amortization	17,303	16,704	49,318	52,395
General and administrative	7,891	4,302	19,755	22,167
Accretion expense	187	142	762	485
Write-down of oil and natural gas properties	—	87,301	95,788	87,301
Rig termination fee	—	—	—	3,641
Acquisition expense	456	—	2,410	—
Total operating expenses	39,276	118,226	200,415	194,517
Income (loss) from operations	16,651	(83,910)	(68,645)	(90,568)
Other (income) expense:				
Interest expense, net of capitalized amounts	831	5,603	10,502	15,567
(Gain) loss on derivative contracts	(5,135)	(23,283)	11,281	(17,463)
Other income, net	(122)	(92)	(299)	(177)
Total other (income) expense	(4,426)	(17,772)	21,484	(2,073)
Income (loss) before income taxes	21,077	(66,138)	(90,129)	(88,495)
Income tax (benefit) expense	(62)	45,667	(62)	38,474
Net income (loss)	21,139	(111,805)	(90,067)	(126,969)
Preferred stock dividends	(1,824)	(1,974)	(5,471)	(5,921)
Income (loss) available to common stockholders	$ 19,315	$ (113,779)	$ (95,538)	$ (132,890)
Income (loss) per common share:				
Basic	$ 0.14	$ (1.72)	$ (0.85)	$ (2.10)
Diluted	$ 0.14	$ (1.72)	$ (0.85)	$ (2.10)
Shares used in computing income (loss) per common share:				
Basic	136,983	66,277	112,925	63,265
Diluted	137,483	66,277	112,925	63,265

i. See “Non-GAAP Financial Measures and Reconciliations” included within this release for related disclosures and calculations

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

	Three Months Ended		Nine Months Ended September	
	2016	**2015**	**2016**	**2015**
Cash flows from operating activities:				
Net income (loss)	$ 21,139	$ (111,805)	$ (90,067)	$ (126,969)
Adjustments to reconcile net loss to cash provided by operating activities:				
Depreciation, depletion and amortization	17,733	16,026	50,560	52,583
Write-down of oil and natural gas properties	—	87,301	95,788	87,301
Accretion expense	187	142	762	485
Amortization of non-cash debt related items	810	781	2,371	2,342
Deferred income tax (benefit) expense	(62)	45,667	(62)	38,474
Net loss on derivatives, net of settlements	(1,044)	(13,494)	27,105	7,635
Non-cash expense related to equity share-based awards	608	368	(253)	(300)
Change in the fair value of liability share-based awards	3,371	64	6,045	4,759
Payments to settle asset retirement obligations	(576)	(1,142)	(895)	(3,047)
Changes in operating assets and liabilities:				
Accounts receivable	(11,608)	(332)	(16,444)	(7,278)
Other current assets	54	116	(251)	31
Current liabilities	15,702	906	19,815	6,455
Acquisition deposit	(32,700)	—	(32,700)	—
Change in other long-term liabilities	—	—	86	100
Change in other assets, net	(1,221)	949	(1,671)	421
Payments to settle vested liability share-based awards related to early retirements	—	—	—	(3,538)
Payments to settle vested liability share-based awards	—	—	(10,300)	(3,925)
Net cash provided by operating activities	12,393	25,547	49,889	55,529
Cash flows from investing activities:				
Capital expenditures	(47,418)	(46,649)	(122,698)	(175,699)
Acquisitions	(18,033)	(1,052)	(302,057)	(2,849)
Proceeds from sales of mineral interests and equipment	(708)	22	22,923	348
Net cash used in investing activities	(66,159)	(47,679)	(401,832)	(178,200)
Cash flows from financing activities:				
Borrowings on senior secured revolving credit facility	74,000	27,000	217,000	130,000
Payments on senior secured revolving credit facility	(114,000)	(3,000)	(257,000)	(66,000)
Payment of deferred financing costs	(640)	—	(640)	—
Issuance of common stock, net	421,908	—	722,715	65,546
Payment of preferred stock dividends	(1,824)	(1,974)	(5,471)	(5,921)
Net cash provided by financing activities	379,444	22,026	676,604	123,625
Net change in cash and cash equivalents	325,678	(106)	324,661	954
Balance, beginning of period	207	2,028	1,224	968
Balance, end of period	$ 325,885	$ 1,922	$ 325,885	$ 1,922

i. See “Non-GAAP Financial Measures and Reconciliations” included within this release for related disclosures and calculations

Non-GAAP Financial Measures and Reconciliations

This news release refers to non-GAAP financial measures such as "Discretionary Cash Flow," "Adjusted Income (Loss)," "Adjusted G&A" and "Adjusted EBITDA," and "Adjusted Total Revenues." 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 useful as an indicator of an oil and natural gas exploration and production company's ability to internally fund exploration and development activities and to service or incur additional debt. The Company also 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 may not relate to the period in which the operating activities occurred. Discretionary cash flow and discretionary cash flow per diluted share are calculated using net income (loss) adjusted for certain items including depreciation, depletion and amortization, the impact of financial derivatives (including the mark-to-market effects, net of cash settlements and premiums paid or received related to our financial derivatives), remaining asset retirement obligations related to our divested offshore properties, restructuring and other non-recurring costs, deferred income taxes and other non-cash income items.
- 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 above details all adjustments to G&A on a GAAP basis to arrive at Adjusted G&A.
- We believe 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 below. Prior to being tax-effected and excluded, the amounts reflected in the determination of Adjusted Income and Adjusted Income per diluted share above were computed in accordance with GAAP.
- We calculate 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, we believe that Adjusted EBITDA provides additional information with respect to our performance or ability to meet its 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 we present may not be comparable to similarly titled measures of other companies.
- We believe that the non-GAAP measure of Adjusted Total Revenues is useful to investors because it provides readers with a revenue value more comparable to other companies who account for derivative contracts and hedges and include their effects in revenue. We believe Adjusted Total Revenue is also useful to investors as a measure of the actual cash inflows generated during the period.

Earnings Call Information

The Company will host a conference call on Thursday, November 3, 2016, to discuss third quarter 2016 financial and operating results.

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

Date/Time:	Thursday, November 3, 2016, at 9:00 a.m. Central Time (10:00 a.m. Eastern Time)
Webcast:	Live webcast will be available at www.callon.com in the "Investors" section of the website
Presentation Slides:	Available at http://ir.callon.com/presentations in the "Investors" section of the website

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

Toll Free:	1-888-349-0096
Canada Toll Free:	1-855-669-9657
International:	1-412-902-0125
Request to join:	Callon Petroleum Company Earnings Call

An archive of the conference call webcast will also be available at www.callon.com in 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.

This news release is posted on the Company's website at www.callon.com and will be archived there for subsequent review under the "News" link on the top of the homepage.

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 2016 guidance and capital expenditure forecast; 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" and words of similar meaning. These statements reflect the Company's current views with respect to future events and financial performance. 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. 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, 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.

For further information contact:
Eric Williams
Manager, Finance
1-800-451-1294