August 8, 2016

Callon Petroleum Company Announces Second Quarter 2016 Results

NATCHEZ, Miss., Aug. 8, 2016 /PRNewswire/ -- Callon Petroleum Company (NYSE: CPE) ("Callon" or the "Company") today reported results of operations for the three months ended June 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 second quarter of 2016 and other recent data points include:

- Net daily production of 13,451 barrels of oil equivalent per day ("BOE/d"), an increase of 8% compared to the first quarter of 2016, comprised of 77% oil volume
- Estimated July 2016 net daily production of over 16,000 BOE/d after a prolonged period of production downtime in June 2016 caused by offsetting completions activity at the Carpe Diem field, compounded by the impact of electrical outages
- Lease operating expense, including workovers, of $5.97 per barrel of oil equivalent ("BOE"), a decrease of 3% from the first quarter of 2016
- GAAP loss per diluted common share of $0.61 and Adjusted Income per fully diluted common share, a non-GAAP financial measure(i), of $0.05
- Closed two Midland Basin transactions for a total purchase price of $362.6 million, including the establishment of a new core operating area in Howard County
- Completed first Callon-operated Wolfcamp A well (completed lateral length of 7,363') in northern Howard County which has produced approximately 48,600 BOE (90% oil) in the first 30 days after being placed on production in early July 2016
- Borrowing base increased 28% from $300 million to $385 million following the closing of recent transactions
- Recently added second horizontal rig to be focused in the WildHorse area in Howard County
- Signed purchase and sale agreement for the acquisition of an incremental 4% working interest in the Casselman and Bohannon fields (the "CaBo area")

"It was an important quarter for our organization, demonstrating our ability to manage through periods of commodity price weakness by living within our cash flow while delivering capital efficient production growth. This solid operating and financial position also allowed us to complete two acquisitions that almost doubled our surface acreage in the Midland Basin, expanding our inventory of investments that we expect will deliver solid returns on capital through all phases of commodity cycles." commented Fred Callon, Chairman and Chief

Executive Officer. "With a strong balance sheet and low cost operating structure, we have returned our second horizontal rig to service in August 2016 and are planning to add a third horizontal rig in early 2017 with continued signs of rebalancing in the oil markets. A large portion of this increased drilling activity will be focused in Howard County, a rapidly emerging core area which has produced encouraging well results from three delineated zones to date, including our recent Wolfcamp A well."

Operations Update

At June 30, 2016, Callon had 118 gross (93.0 net) horizontal wells producing from five established zones. Our net daily production for the three months ended June 30, 2016, grew approximately 41% to 13,451 BOE/d (approximately 77% oil) as compared to the same period of 2015. Sequentially, we grew production more than 8% compared to the first quarter of 2016.

For the three months ended June 30, 2016, we drilled 6 gross (3.7 net) horizontal wells, completed 5 gross (3.4 net) horizontal wells, and placed 5 gross (3.4 net) horizontal wells on production. As of June 30, 2016, we had 6 gross (4.2 net) horizontal wells awaiting completion, including 2 gross drilled, uncompleted wells recently acquired as part of our western Reagan County transaction.

Monarch

Production from the Monarch areas was adversely impacted during most of the month of June 2016 by production disruptions at our largest producing field, Carpe Diem. Several wells in the field experienced hydraulic interference from two offsetting completions being performed by other operators offsetting the eastern side of Carpe Diem. The situation was compounded by power outages caused by adverse weather conditions which hindered our efforts to de-water the wells in order to restore normalized production levels. We estimate that this unexpected downtime negatively impacted total net production volumes in the quarter by approximately 425 BOE/d.

	For the Three Months Ended June 30, 2016							
	Drilled		Completed		Placed on Production		Awaiting Completion	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Monarch	6	3.7	4	2.4	5	3.4	4	3.1

During the second quarter, we continued our focus on development of the Lower Spraberry on our Monarch assets in Midland County. For the three months ended June 30th, we drilled 6 gross (3.7 net) wells, completed 4 gross (2.4 net) wells and placed 5 gross (3.4 net) wells on production. Since placing our first two Lower Spraberry wells on production in November 2014, we now have 28 gross wells producing from two levels of this zone across our asset base, including 25 at Monarch, with drilled lateral lengths ranging from 5,000' to 10,000'.

24-Hour IP Date	Well	County	Completed Lateral (ft)	24-Hour Peak IP (BOE/d; Two-stream) [a]			30-Day Average Peak IP (BOE/d; Two-stream)		
				Peak 24-Hour IP	Production (% oil)	Per 1,000' Lateral Feet	Peak 30-Day IP	Production (% oil)	Per 1,000' Lateral Feet
06/21/2016	Pecan Acres 22A2 09SH	Midland	4,652'	729	87%	157	745	85%	160
06/21/2016	Pecan Acres 22A3 10SH	Midland	4,432'	719	87%	162	741	87%	167
06/02/2016	Casselman 8 18SH	Midland	4,675'	839	85%	180	674	84%	144
05/29/2016	Casselman 8 16SH	Midland	4,671'	867	79%	186	638	86%	137
05/25/2016	Kendra-Annie 10 21SH	Midland	8,178'	935	89%	114	697	89%	85
05/04/2016	Casselman 8 17SH	Midland	4,903'	923	83%	188	668	87%	136
04/17/2016	Kendra-Amanda 29SH	Midland	8,432'	1,242	89%	147	926	89%	110
04/01/2016	Casselman 10 09SH	Midland	4,182'	674	90%	161	562	87%	134

(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.

We continue to deliver strong, consistent well results and capital efficiency from our Monarch development program. As detailed in the table above, eight Lower Spraberry wells, all in the lower bench of the zone (or, "LLS"), achieved 24-hour peak initial production ("IP") rates during the quarter. The LLS wells averaged a 24-hour peak IP of 866 Boe/d (or 162 Boepd per 1,000') and a 30-day average peak IP of 706 Boe/d (or 134 Boepd per 1,000').

At our Pecan Acres field, we placed 3 gross (1.4 net) LLS wells on production. While one of the wells continues to build towards its 30-day average peak IP, the other two wells yielded an average 30-day average peak IP of 743 BOE/d (86% oil) or 164 BOE/d per 1,000' from an average drilled lateral length of approximately 5,000'. We also plan to commence completion operations on our first Wolfcamp A well in the Monarch area in August 2016 which is being developed as a stacked lateral with a LLS well. Each of the wells was drilled to a lateral length of approximately 10,000'.

We are currently completing a three-well pad with an average drilled lateral length of approximately 9,750' in our Carpe Diem field with two of the wells targeting the upper section of the Lower Spraberry ("ULS") and the third well targeting the LLS. This pad was drilled on 11 wells-per-section spacing, supported by long-term production and pressure data from our previous well density tests. In addition, we plan to drill an additional two LLS wells at Carpe Diem in the third quarter with planned drilled lateral lengths of 10,000' that were increased from a previous planned lateral length of 5,000' after a recently completed partnership agreement with an offset operator.

We continue to build upon our well density tests of the Lower Spraberry in the Monarch area which have been focused on the Carpe Diem field to date. The next step in our progression of this initiative will be a 13 wells-per-section test in the CaBo area that was spud in July 2016, with two wells landed in the LLS and the third landed in the ULS.

Callon recently signed a purchase agreement for the acquisition of an incremental 4% working interest in the CaBo area, increasing our working interest in the area to approximately 75%. The purchase price for the acquired interest is $13 million with an effective date of August 1, 2016. Completion of the acquisition is subject to customary closing conditions.

WildHorse

	For the Three Months Ended June 30, 2016							
	Drilled		Completed		Placed on Production		Awaiting Completion	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
WildHorse	—	—	1	1.0	—	—	—	—

During the second quarter, we began our first operated completion in the recently acquired WildHorse area in Howard County, Texas. The well (Silver City Unit A #1H; 100% WI) was completed in the Wolfcamp A with a lateral length of 7,363'. It is the northernmost Wolfcamp A completion to date on our operated acreage, located in our Sidewinder field in northwest Howard County. After a first oil production date on July 3, 2016, the well has produced approximately 48,600 BOE (90% oil) during the first 30 days of production.

We anticipate initiating our operated drilling program in Howard County during the fourth quarter of 2016 with a dedicated one-rig program. The rig will initially drill two-well pads in the Wolfcamp A at our Fairway acreage in central Howard County, before expanding its scope to include our broader footprint and other prospective zones in 2017, including the Lower Spraberry and Wolfcamp B. We currently expect to place our first two-well pad from this program on production in mid-December 2016. Additionally, we are preparing to further increase our drilling activity in the WildHorse area should commodity prices warrant the addition of a third rig to our operated drilling program.

Ranger

			24-Hour Peak IP (BOE/d; Two-stream)			30-Day Average Peak IP (BOE/d; Two-stream)		
Well	County	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
Turner AR Unit B 08HK	Reagan	7,518'	1,716	86%	228	1,279	86%	170
Turner AR Unit C 13HK	Reagan	7,430'	1,758	86%	237	1,253	86%	169

The two wells listed in the table above were completed using a new generation completion design employed by the previous operator of our newly acquired Lonesome Draw field, which included shorter stage lengths and higher proppant volumes. We will continue to evaluate the longer-term performance of wells completed with this enhanced design, but early indications include 30-day average peak IPs trending approximately 50% higher versus older generation completions we used in the Ranger area. We plan to incorporate these enhanced completion techniques in two upcoming completions of drilled, uncompleted wells acquired at Lonesome Draw. These wells will be targeting the Wolfcamp A and Upper Wolfcamp B zones and are planned to commence completion operations in August 2016.

Capital expenditures

For the three months ended June 30, 2016, we accrued $21.3 million in operational capital expenditures, including facilities expenditures of $4.0 million, compared to $35.0 million in the first quarter of 2016. Total capital expenditures, inclusive of capitalized expenses, are detailed below on an accrual and cash basis (in thousands):

	Three Months Ended June 30, 2016			
	Operational Capital Expenditures	Capitalized Interest	Capitalized G&A	Total Capital Expenditures
Cash basis [(a)]	$ 17,965	$ 3,687	$ 2,853	$ 24,505
Timing adjustments [(b)]	3,309	(150)	—	3,159
Non-cash items	—	—	1,854	1,854
Accrual (GAAP) basis	$ 21,274	$ 3,537	$ 4,707	$ 29,518

(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.

Operating and Financial Results

The following table presents summary information for the periods indicated:

	Three Months Ended		
	June 30, 2016	March 31, 2016	June 30, 2015
Net production:			
Oil (MBbls)	948	892	685
Natural gas (MMcf)	1,658	1,443	1,084
Total production (MBOE)	1,224	1,132	866
Average daily production (BOE/d)	13,451	12,440	9,516
% oil (BOE basis)	77%	79%	79%
Oil and natural gas revenues (in thousands):			
Oil revenue	$ 40,555	$ 27,443	$ 36,093
Natural gas revenue	4,590	3,255	3,149
Total revenue	$ 45,145	$ 30,698	$ 39,242
Impact of cash-settled derivatives	4,017	7,716	4,965
Adjusted Total Revenue (i)	$ 49,162	$ 38,414	$ 44,207

Total Revenue. For the quarter ended June 30, 2016, Callon reported total revenues of $45.2 million and total revenues including cash-settled derivatives ("Adjusted Total Revenue," a non-GAAP financial measure(i)) of $49.2 million, including the $4.0 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 13,451 BOE/d compared to average daily production of 12,440 BOE/d in the first quarter of 2016. Average realized prices, including and excluding the effects of hedging, are detailed below.

Hedging impacts. For the quarter ended June 30, 2016, Callon recognized the following hedging-related items:

	In Thousands	Per Unit
Oil derivatives contracts		
Net gain on settlements	$ 3,707	$ 3.91
Net loss on fair value adjustments	(18,466)	
Total net loss on oil derivatives contracts	$ (14,759)	
Natural gas derivatives contracts		
Net gain on settlements	$ 310	$ 0.19
Net gain on fair value adjustments	(1,035)	
Total net gain on natural gas derivatives contracts	$ (725)	
Total derivatives contracts		
Net gain on settlements	$ 4,017	$ 3.29
Net loss on fair value adjustments	(19,501)	
Total net loss on total derivatives contracts	$ (15,484)	

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

	Three Months Ended June 30, 2016
Average realized sales price	
Oil (per Bbl) (excluding impact of cash-settled derivatives)	$ 42.78
Impact of cash-settled derivatives	3.91
Oil (per Bbl) (including impact of cash-settled derivatives)	$ 46.69
Natural gas (per Mcf) (excluding impact of cash-settled derivatives)	$ 2.77
Impact of cash-settled derivatives	0.19
Natural gas (per Mcf) (including impact of cash-settled derivatives)	$ 2.96
Total (per BOE) (excluding impact of cash-settled derivatives)	$ 36.88
Impact of cash-settled derivatives	3.29
Total (per BOE) (including impact of cash-settled derivatives)	$ 40.17

	Three Months Ended		
Additional per BOE data:	**June 30, 2016**	**March 31, 2016**	**June 30, 2015**
Sales price, excluding impact of cash-settled derivatives	$ 36.88	$ 27.12	$ 45.31
Sales price, including impact of cash-settled derivatives	40.17	33.93	51.05
Lease operating expense	$ 5.97	$ 6.15	$ 7.59
Production taxes	2.01	1.96	3.41
Depletion, depreciation and amortization	13.31	13.89	20.31
G&A	5.15	4.91	6.65
Adjusted G&A - total (a)	3.55	4.10	4.53
Adjusted G&A - cash component (b)	2.92	3.55	3.85

(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 June 30, 2016 was $5.97 per BOE, compared to LOE of $6.15 per BOE in the first quarter of 2016.

Production Taxes, including ad valorem taxes. Production taxes were $2.01 per BOE in the second quarter of 2016, representing approximately 5.4% of total revenue before the impact of derivative settlements.

Depreciation, Depletion and Amortization ("DD&A"). DD&A for the three months ended June 30, 2016 was $13.31 per BOE compared to $13.89 per BOE in the first quarter of 2016, with the decrease in per unit DD&A being attributable to increases in proved reserves relative to our depreciable asset base and assumed future development costs related to undeveloped proved reserves. The decrease in our depreciable base was primarily related to the write-down of oil and natural gas properties during 2015 and the first half of 2016.

General and Administrative ("G&A"). G&A for the second quarter of 2015 was $6.3 million, or $5.15 per BOE, compared to $5.6 million, or $4.91 per BOE, for the first quarter of 2016. G&A, excluding certain non-cash incentive share-based compensation valuation adjustments, ("Adjusted G&A", a non-GAAP measure[i]) was $4.3 million, or $3.55 per BOE, for the second quarter of 2016 compared to $4.6 million, or $4.10 per BOE, for the first quarter of 2016. The cash component of Adjusted G&A was $3.6 million, or $2.92 per BOE, for the second quarter of 2016 compared to $4.0 million, or $3.55 per BOE, for the first quarter of 2016.

For the second 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):

G&A expenses	Cash	Non-Cash	Total
Cash G&A	$ 3,578	$ —	$ 3,578
Restricted stock share-based compensation	—	655	655
Change in the fair value of liability share-based awards	—	1,954	1,954
Corporate depreciation & amortization	—	115	115
Total G&A expense:	$ 3,578	$ 2,724	$ 6,302
Adjusted G&A (i)			
Less: Change in the fair value of liability share-based awards			$ (1,954)
Adjusted G&A – total			4,348
Restricted stock share-based compensation			(655)
Corporate depreciation & amortization			(115)
Adjusted G&A – cash component			$ 3,578

Write-down of Oil and Natural Gas Properties. As a result of the ceiling test limitation, the Company recognized a write-down of oil and natural gas properties of $61.0 million in the second quarter of 2016.

Income (Loss) Available to Common Shareholders. The Company reported a net loss available to common shareholders of $71.9 million in the second quarter of 2016 and Adjusted Income available to common shareholders of $6.1 million, or $0.05 per diluted share.

Capital Budget Update

Following the closing of its recent Midland Basin acquisitions, the Company has completed a review of its operational plans for the balance of 2016. Callon recently returned a second horizontal rig to service after being idled in the first quarter of 2016. The rig will initially be focused on program development of the Wolfcamp A zone in the WildHorse area after drilling two 10,000' lateral wells targeting the LLS at the Carpe Diem field. In addition, the Company has budgeted for investments in facilities, seismic and land to support the longer-term development plans in each of our focus areas, including the potential addition of a third horizontal rig during the first half of 2017.

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

	1st Half 2016	Estimated 2nd Half 2016	Total
Operational activity (gross / net)			
Drill wells	11 / 8.0	15 / 10.2	26 / 18.2
Completed wells	14 / 10.5	15 / 10.3	29 / 20.8
Wells placed on production	13 / 9.5	13 / 8.9	26 / 18.4
Capital expenditures (in millions, accrual basis)			
Drilling and completion	$ 46.2	$ 58.4	$ 104.6
Facilities	9.2	16.2	25.4
Operational capital expenditures	55.4	74.6	130.0
Seismic	0.8	2.5	3.3
Land and other	—	6.7	6.7
Total capital expenditures (excl. capitalized expenses)	$ 56.2	$ 83.8	$ 140.0

2016 Guidance Update

	Third Quarter 2016 Guidance	Updated Full Year 2016 Guidance	Full Year [a] Guidance Change
Total production (BOE/d)	16,000 - 17,000	14,500 - 15,500	500
% oil	75% - 77%	76% - 80%	(1%)
% oil hedged [b]	49%	48%	
Average swap/long-put price [b]	$48.84	$50.04	
Expenses (per BOE)			
LOE, including workovers	$5.75 - $6.25	$5.75 - $6.25	$(1.00)
Production taxes, including ad valorem (% unhedged revenue)	7%	7%	—
Adjusted G&A [c]	$3.25 - $3.75	$3.25 - $3.75	$(0.05)
Adjusted G&A - cash component [d]	$2.50 - $3.00	$2.35 - $2.85	$(0.55)
Total capital expenditures			
Accrual basis ($MM)	$34 - $38	$140	$40

(a) Based on the midpoint of guidance.

(b) Volumes presented in the Updated Full Year 2016 Guidance column include volumes hedged and the average swap/long put price for the remainder of the year only.

(c) 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.

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

Hedge Portfolio Summary

The following table summarizes our open derivative positions as of August 8, 2016:

Oil contracts	For the Remainder of 2016	For the Full Year of 2017
Swap contracts (WTI)		
Total volume (MBbls)	460	—
Weighted average price per Bbl	$ 58.10	$ —
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)	276	—
Weighted average price per Bbl		
Ceiling (short call option)	$ 63.33	$ —
Floor (long put option)	$ 53.33	$ —
Short put option	$ 38.77	$ —
Collar contracts (WTI, two-way collars)		
Total volume (MBbls)	368	438
Weighted average price per Bbl		
Ceiling (short call)	$ 46.50	$ 59.05
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)	736	—
Weighted average price per Bbl	$ 0.17	$ —
Natural gas contracts		
Swap contracts (Henry Hub)		
Total volume (BBtu)	1,104	—
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

The following tables reconcile to the related GAAP measure the Company's loss available to common stockholders to Adjusted Income and the Company's net loss to Adjusted EBITDA (in thousands):

	Three Months Ended		
	June 30, 2016	March 31, 2016	June 30, 2015
Loss available to common stockholders	$ (71,920)	$ (42,933)	$ (6,940)
Valuation allowance	24,409	14,288	—
Write-down of oil and natural gas properties	39,658	22,604	—
Net loss (gain) on derivatives, net of settlements	12,676	5,621	8,590
Change in the fair value of share-based awards	1,277	461	1,045
Withdrawn proxy contest expenses	2	144	150
Adjusted Income	$ 6,102	$ 185	$ 2,845
Adjusted Income per fully diluted common share	$ 0.05	$ 0.00	$ 0.04

	Three Months Ended		
	June 30, 2016	March 31, 2016	June 30, 2015
Net loss	$ (70,097)	$ (41,109)	$ (4,967)
Write-down of oil and natural gas properties	61,012	34,776	—
Net loss (gain) on derivatives, net of settlements	19,501	8,648	13,214
Change in the fair value of share-based awards	2,628	1,225	2,086
Withdrawn proxy contest expenses	3	221	230
Acquisition expense	1,906	48	—
Income tax benefit	—	—	(2,116)
Interest expense	4,180	5,491	5,106
Depreciation, depletion and amortization	16,698	16,129	18,011
Accretion expense	395	180	134
Adjusted EBITDA	$ 36,226	$ 25,609	$ 31,698

Discretionary Cash Flow. Discretionary cash flow, a non-GAAP measure[(i)], for the second quarter of 2016 was $29.0 million and is reconciled to operating cash flow in the following table (in thousands):

	Three Months Ended		
	June 30, 2016	March 31, 2016	June 30, 2015
Cash flows from operating activities:			
Net loss	**$** (70,097)	$ (41,109)	$ (4,967)
Adjustments to reconcile net loss to cash provided by operating activities:			
Depreciation, depletion and amortization	16,698	16,129	18,011
Write-down of oil and natural gas properties	61,012	34,776	—
Accretion expense	395	180	134
Amortization of non-cash debt related items	780	781	780
Deferred income tax (benefit) expense	—	—	(2,116)
Net loss (gain) on derivatives, net of settlements	19,501	8,648	13,214
Non-cash expense related to equity share-based awards	(1,253)	392	(754)
Change in the fair value of liability share-based awards	1,965	709	1,607
Discretionary cash flow	$ 29,001	$ 20,506	$ 25,909
Changes in working capital	(6,974)	5,582	438
Payments to settle asset retirement obligations	(158)	(161)	(2,163)
Payments to settle vested liability share-based awards	(493)	(9,807)	(326)
Net cash provided by operating activities	$ 21,376	$ 16,120	$ 23,858

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

	June 30, 2016 Unaudited	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$ 207	$ 1,224
Accounts receivable	44,460	39,624
Fair value of derivatives	5,537	19,943
Other current assets	1,766	1,461
Total current assets	51,970	62,252
Oil and natural gas properties, full cost accounting method:		
Evaluated properties	2,530,978	2,335,223
Less accumulated depreciation, depletion, amortization and impairment	(1,883,806)	(1,756,018)
Net oil and natural gas properties	647,172	579,205
Unevaluated properties	379,605	132,181
Total oil and natural gas properties	1,026,777	711,386
Other property and equipment, net	9,971	7,700
Restricted investments	3,323	3,309
Deferred financing costs	3,076	3,642
Fair value of derivatives	60	—
Other assets, net	413	305
Total assets	$ 1,095,590	$ 788,594
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 71,960	$ 70,970
Accrued interest	6,258	5,989
Cash-settleable restricted stock unit awards	5,168	10,128
Asset retirement obligations	3,933	790
Fair value of derivatives	7,491	—
Total current liabilities	94,810	87,877
Senior secured revolving credit facility	40,000	40,000
Secured second lien term loan, net of unamortized deferred financing costs	289,559	288,565
Asset retirement obligations	2,164	4,317
Cash-settleable restricted stock unit awards	4,141	4,877
Fair value of derivatives	6,313	—
Other long-term liabilities	286	200
Total liabilities	437,273	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; 131,090,644 and 80,087,148 shares outstanding, respectively	1,311	801
Capital in excess of par value	1,112,873	702,970
Accumulated deficit	(455,882)	(341,029)
Total stockholders' equity	658,317	362,758
Total liabilities and stockholders' equity	$ 1,095,590	$ 788,594

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Operating revenues:				
Oil sales	$ 40,555	$ 36,093	$ 67,998	$ 64,002
Natural gas sales	4,590	3,149	7,845	5,631
Total operating revenues	45,145	39,242	75,843	69,633
Operating expenses:				
Lease operating expenses	7,311	6,575	14,268	13,534
Production taxes	2,455	2,952	4,675	5,217
Depreciation, depletion and amortization	16,293	17,587	32,015	35,691
General and administrative	6,302	5,763	11,864	17,865
Accretion expense	395	134	575	343
Write-down of oil and natural gas properties	61,012	—	95,788	—
Rig termination fee	—	—	—	3,641
Acquisition expense	1,906	—	1,954	—
Total operating expenses	95,674	33,011	161,139	76,291
Income (loss) from operations	(50,529)	6,231	(85,296)	(6,658)
Other (income) expense:				
Interest expense, net of capitalized amounts	4,180	5,106	9,671	9,964
Loss on derivative contracts	15,484	8,249	16,416	5,820
Other income, net	(96)	(41)	(177)	(85)
Total other expense	19,568	13,314	25,910	15,699
Loss before income taxes	(70,097)	(7,083)	(111,206)	(22,357)
Income tax benefit	—	(2,116)	—	(7,193)
Net loss	(70,097)	(4,967)	(111,206)	(15,164)
Preferred stock dividends	(1,823)	(1,973)	(3,647)	(3,947)
Loss available to common stockholders	$ (71,920)	$ (6,940)	$ (114,853)	$ (19,111)
Loss per common share:				
Basic	$ (0.61)	$ (0.11)	$ (1.14)	$ (0.31)
Diluted	$ (0.61)	$ (0.11)	$ (1.14)	$ (0.31)
Shares used in computing loss per common share:				
Basic	118,209	66,038	100,895	61,759
Diluted	118,209	66,038	100,895	61,759

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	**2015**	**2016**	**2015**
Cash flows from operating activities:				
Net loss	$ (70,097)	$ (4,967)	$ (111,206)	$ (15,164)
Adjustments to reconcile net loss to cash provided by operating activities:				
Depreciation, depletion and amortization	16,698	18,011	32,827	36,557
Write-down of oil and natural gas properties	61,012	—	95,788	—
Accretion expense	395	134	575	343
Amortization of non-cash debt related items	780	780	1,561	1,561
Deferred income tax benefit	—	(2,116)	—	(7,193)
Net loss on derivatives, net of settlements	19,501	13,214	28,149	21,129
Non-cash expense related to equity share-based awards	(1,253)	(754)	(861)	(668)
Change in the fair value of liability share-based awards	1,965	1,607	2,674	4,695
Payments to settle asset retirement obligations	(158)	(2,163)	(319)	(1,905)
Changes in operating assets and liabilities:	—	—		
Accounts receivable	(10,777)	(4,821)	(4,836)	(6,946)
Other current assets	(885)	(536)	(305)	(85)
Current liabilities	4,830	5,904	4,113	5,549
Change in other long-term liabilities	75	100	86	100
Change in other assets, net	(217)	(209)	(450)	(528)
Payments to settle vested liability share-based awards related to early retirements	—	—	—	(3,538)
Payments to settle vested liability share-based awards	(493)	(326)	(10,300)	(3,925)
Net cash provided by operating activities	21,376	23,858	37,496	29,982
Cash flows from investing activities:				
Capital expenditures	(24,505)	(60,067)	(75,280)	(129,050)
Acquisitions	(273,841)	—	(284,024)	(1,797)
Proceeds from sales of mineral interests and equipment	23,631	54	23,631	326
Net cash used in investing activities	(274,715)	(60,013)	(335,673)	(130,521)
Cash flows from financing activities:				
Borrowings on senior secured revolving credit facility	98,000	43,000	143,000	103,000
Payments on senior secured revolving credit facility	(58,000)	(5,000)	(143,000)	(63,000)
Payment of deferred financing costs	—	12	—	—
Issuance of common stock, net	205,858	—	300,807	65,546
Payment of preferred stock dividends	(1,823)	(1,973)	(3,647)	(3,947)
Net cash provided by financing activities	244,035	36,039	297,160	101,599
Net change in cash and cash equivalents	(9,304)	(116)	(1,017)	1,060
Balance, beginning of period	9,511	2,144	1,224	968
Balance, end of period	$ 207	$ 2,028	$ 207	$ 2,028

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 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 Tuesday, August 9, 2016, to discuss second quarter 2016 financial and operating results.

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

Date/Time: Tuesday, August 9, 2016, at 8:00 a.m. Central Time (9:00 a.m. Eastern Time)
Webcast: Live webcast will be available atwww.callon.com 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 atwww.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 atwww.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 the consummation of the pending transactions, wells anticipated to be drilled and placed on production, future levels of drilling activity and associated production, the Company's 2016 guidance, capital budget amounts and expected cash flows, reserve quantities and the present value thereof, 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. Without limiting the foregoing, forward-looking statements contained in this news release specifically include the expectation of total reserve potential and EUR. 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 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:
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i. See "Non-GAAP Financial Measures and Reconciliations" included within this release for related disclosures and calculations

To view the original version on PR Newswire, visit:http://www.prnewswire.com/news-releases/callon-petroleum-company-announces-second-quarter-2016-results-300310672.html

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