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NEWS RELEASE

SOUTHWESTERN ENERGY ANNOUNCES OPERATIONAL UPDATE AND 2016 FINANCIAL RESULTS

Houston, Texas – February 23, 2017...Southwestern Energy Company (NYSE: SWN) today announced its financial and operating results for the fourth quarter and the year ended December 31, 2016. Calendar year 2016 highlights include:

- Net cash provided by operating activities of $498 million and net cash flow of $645 million;
- Net loss attributable to common stock of $2.8 billion, or $6.32 per diluted share, and adjusted net loss attributable to common stock of $7 million, or $0.01 per diluted share;
- Total net production of 875 Bcfe, including 498 Bcfe from the Appalachia Basin and 375 Bcf from the Fayetteville Shale;
- Encouraging results associated with Northeast Appalachia completion testing and production flow optimization, including an aggregate initial production rate of approximately 92 million cubic feet per day from five wells on the Cramer pad that were placed to sales in the fourth quarter;
- First sales successfully commenced in Tioga County, Pennsylvania;
- Positive early results from the Company's first drilled and completed Utica well in Marshall County, West Virginia;
- Upward proved reserves performance revisions of 683 Bcfe, reflecting the continued improvement in ultimate well recoveries and lower costs; and
- Proved Developed Producing (PDP) Finding and Development costs for the total company of $0.75 per Mcfe, a 15% improvement from prior year.

"The bold and decisive approach in which we tackled 2016 delivered remarkable results," said Bill Way, President and Chief Executive Officer of Southwestern Energy. "The progress made in improving our financial strength and the operational excellence that facilitated our mid-year resumption of drilling and completion activities has the Company positioned well to create long-term value for our shareholders."

The Company delivered on all of the initiatives promised at the beginning of 2016, which included strengthening the balance sheet and enhancing margins. As a result, the Company extended its liquidity through 2020 and ended the year with total debt of $4.7 billion and net debt of $3.2 billion, reducing its net debt by $1.5 billion compared to the end of 2015. Additionally, the Company was able to reduce cash operating costs, which includes lease operating expense, general and administrative expense and taxes other than income, by $0.04 per Mcfe through a relentless focus on margin enhancements and operational efficiencies. Below is a summary of fourth quarter and full year 2016 results.

Fourth Quarter and Year-end 2016 Financial Results
Southwestern Energy Company and Subsidiaries

(in millions, except per share amounts)	For the three months ended December 31, 2016	2015	For the year ended December 31, 2016	2015
Operating income (loss)	**$ 122**	$ (2,561)	**$ (2,195)**	$ (6,522)
Adjusted operating income (non-GAAP measure)	**$ 134**	$ 8	**$ 215**	$ 146
Net loss attributable to common stock	**$ (237)**	$ (2,134)	**$ (2,751)**	$ (4,662)
Adjusted net income (loss) attributable to common stock (non-GAAP measure)	**$ 39**	$ (6)	**$ (7)**	$ 71
Loss per share	**$ (0.48)**	$ (5.58)	**$ (6.32)**	$ (12.25)
Adjusted earnings (loss) per share (non-GAAP measure)	**$ 0.08**	$ (0.02)	**$ (0.01)**	$ 0.19
Net cash provided by operating activities	**$ 161**	$ 353	**$ 498**	$ 1,580
Net cash flow (non-GAAP measure)	**$ 211**	$ 306	**$ 645**	$ 1,468

Exploration and Production 2016 Financial Results	For the three months ended December 31, 2016	2015	For the year ended December 31, 2016	2015
Production				
Fayetteville (Bcf)	**86**	112	**375**	465
Northeast Appalachia (Bcf)	**82**	97	**350**	360
Southwest Appalachia (Bcfe)	**33**	40	**148**	143
Other (Bcfe)	**1**	–	**2**	8
Total production (Bcfe)	**202**	249	**875**	976
% Natural Gas	**90%**	91%	**90%**	92%
Average unit costs per Mcfe				
Lease operating expenses	**$ 0.87**	$ 0.91	**$ 0.87**	$ 0.92
General & administrative expenses[(1)]	**$ 0.27**	$ 0.20	**$ 0.22**	$ 0.21
Taxes, other than income taxes[(2)]	**$ 0.11**	$ 0.09	**$ 0.10**	$ 0.10
Full cost pool amortization	**$ 0.30**	$ 0.78	**$ 0.38**	$ 1.00

(1) Excludes restructuring and other one-time charges for the three months and year ended December 31, 2016, respectively.

(2) Excludes restructuring charges for the year ended December 31, 2016.

Realized Prices	For the three months ended December 31,		For the year ended December 31,	
	2016	2015	**2016**	2015
Natural Gas Price:				
NYMEX Henry Hub Price ($/MMBtu)[1]	**$ 2.98**	$ 2.27	**$ 2.46**	$ 2.66
Discount to NYMEX[2]	**$ (0.98)**	$ (0.79)	**$ (0.87)**	$ (0.75)
Average realized gas price per Mcf, excluding hedges	**$ 2.00**	$ 1.48	**$ 1.59**	$ 1.91
Gain (loss) on settled financial basis derivatives ($/Mcf)	**$ 0.09**	$ 0.02	**$ 0.03**	$ (0.00)
Gain (loss) on settled commodity derivatives ($/Mcf)	**$ (0.02)**	$ 0.57	**$ 0.02**	$ 0.46
Average realized gas price per Mcf, including hedges	**$ 2.07**	$ 2.07	**$ 1.64**	$ 2.37
Oil Price:				
WTI oil price ($/Bbl)	**$ 49.29**	$ 42.18	**$ 43.32**	$ 48.80
Discount to WTI	**$ (8.11)**	$ (14.82)	**$ (12.12)**	$ (15.55)
Average oil price per Bbl	**$ 41.18**	$ 27.36	**$ 31.20**	$ 33.25
NGL Price:				
Average net realized NGL price per Bbl	**$ 12.08**	$ 7.62	**$ 7.46**	$ 6.80
Percentage of WTI	**25%**	18%	**17%**	14%

(1) Based on last day settlement prices from monthly futures contracts.

(2) This discount includes a basis differential, physical basis hedges, third-party transportation charges and fuel charges and excludes financial basis hedges.

Fourth Quarter of 2016 Financial Results

E&P Segment – The operating income from the Company's E&P segment was $82 million for the fourth quarter of 2016, improved from an operating loss of $2.6 billion during the fourth quarter of 2015 due to a $2.6 billion impairment of natural gas and oil properties during that quarter. Excluding impairments and other one-time charges, adjusted operating income from the Company's E&P segment was $94 million for the fourth quarter of 2016, compared to an adjusted operating loss of $64 million for the same period in 2015. The increase in adjusted operating income was primarily due to lower operating costs and higher realized liquids prices partially offset by decreased production. The decreased production was a result of limited activity in 2016 due to lower natural gas prices.

Midstream Segment – Operating income for the Company's Midstream segment, comprised of gathering and marketing activities, was $40 million for the fourth quarter of 2016, compared to $72 million for the same period in 2015. The decrease in operating income was largely due to a decrease in volumes gathered, resulting from lower production volumes in the Fayetteville Shale.

Full Year 2016 Financial Results

E&P Segment – The operating loss from the Company's E&P segment was $2.4 billion for 2016, compared to an operating loss of $7.1 billion for 2015. The E&P segment recorded a $2.3 billion impairment of natural gas and oil properties for the year ended December 31, 2016 compared to a $7.0 billion impairment for the same period in 2015. Excluding impairments, the improvement in operating loss was primarily due to lower operating costs and expenses and increasing NGL realizations, partially offset by lower realized natural gas prices and decreased production. Adjusted operating income from the Company's E&P segment was $3 million for 2016, compared to an adjusted operating loss of $159 million in 2015.

Midstream Services – Operating income for the Company's Midstream segment was $209 million for 2016, compared to $583 million for the same period in 2015. The decrease in operating income was primarily due to 2015 including a $277 million net gain on sale of assets divested. Adjusted operating income for the Company's Midstream segment was $212 million for 2016 compared to $306 million for the same period in 2015. The decrease in adjusted operating income was largely due to a decrease in volumes gathered resulting from lower production volumes in the Fayetteville Shale and the sale of the Company's northeast Pennsylvania gathering assets.

Capital Investments – During 2016, Southwestern invested a total of $648 million. This included approximately $623 million invested in its E&P business, $21 million invested in its Midstream segment and $4 million invested for corporate and other purposes. Of the $648 million, approximately $152 million was associated with capitalized interest and $89 million was associated with capitalized expenses.

2016 Natural Gas and Oil Reserves

Southwestern's estimated proved natural gas and oil reserves totaled approximately 5,253 Bcfe at December 31, 2016, compared to 6,215 Bcfe at the end of 2015. The decrease in the Company's reserves in 2016 was primarily due to downward price revisions associated with decreased commodity prices and 2016 production, partially offset by upward performance revisions and the Company's successful development activity in Northeast Appalachia, Southwest Appalachia and the Fayetteville Shale. The average prices from the first day of each month from the previous twelve months utilized to value the Company's estimated proved natural gas and oil reserves at December 31, 2016 were $2.48 per MMBtu for natural gas, $39.25 per barrel for oil and $6.74 per barrel for NGLs, compared to $2.59 per MMBtu for natural gas, $46.79 per barrel for oil and $6.82 per barrel for NGLs at December 31, 2015. Approximately 93% of the Company's estimated proved reserves were natural gas and 99% were classified as proved developed at year-end 2016, compared to 95% and 93%, respectively, at year-end 2015.

The following table details additional information relating to reserve estimates as of and for the year ended December 31, 2016:

	Natural Gas (Bcf)	Oil (MBbls)	NGL (MBbls)	Total (Bcfe)
Proved reserves, beginning of year	5,917	8,753	40,947	6,215
Revisions of previous estimates	(446)	1,564	13,794	(354)
Extensions, discoveries and other additions	198	2,417	11,576	282
Production	(788)	(2,192)	(12,372)	(875)
Acquisition of reserves in place	–	–	–	–
Disposition of reserves in place	(15)	(19)	(14)	(15)
Proved reserves, end of year	4,866	10,523	53,931	5,253
Proved developed reserves:				
Beginning of year	5,474	8,753	40,947	5,772
End of year	4,789	10,523	53,931	5,176

Note: Amounts may not add due to rounding

2016 PROVED RESERVES BY DIVISION

	Appalachia		Fayetteville		
	Northeast	Southwest	Shale	Other	Total
Estimated Proved Reserves (Bcfe):					
Reserves, beginning of year	**2,319**	**611**	**3,281**	**4**	**6,215**
Production	(350)	(148)	(375)	(2)	**(875)**
Extensions, discoveries and other additions	81	157	44	–	**282**
Disposition of reserves in place	–	(15)	–	–	**(15)**
Price revisions	(794)	(127)	(116)	–	**(1,037)**
Performance & production revisions	318	199	163	3	**683**
Reserves, end of year	**1,574**	**677**	**2,997**	**5**	**5,253**

The following table provides an overall and by category summary of the Company's natural gas, oil and NGL reserves as of December 31, 2016 and sets forth 2016 annual information related to production and capital investments for each of its operating areas:

2016 PROVED RESERVES BY CATEGORY AND SUMMARY OPERATING DATA

	Appalachia		Fayetteville		
	Northeast	Southwest	Shale	Other (1)	Total
Estimated Proved Reserves:					
Natural Gas (Bcf):					
Developed (Bcf)	1,540	293	2,954	2	**4,789**
Undeveloped (Bcf)	34	–	43	–	**77**
	1,574	293	2,997	2	**4,866**
Crude Oil (MMBbls):					
Developed (MMBbls)	–	10.2	–	0.3	**10.5**
Undeveloped (MMBbls)	–	–	–	–	**–**
	–	10.2	–	0.3	**10.5**
Natural Gas Liquids (MMBbls):					
Developed (MMBbls)	–	53.8	–	0.1	**53.9**
Undeveloped (MMBbls)	–	–	–	–	**–**
	–	53.8	–	0.1	**53.9**
Total Proved Reserves (Bcfe):					
Developed (Bcfe)	1,540	677	2,954	5	**5,176**
Undeveloped (Bcfe)	34	–	43	–	**77**
	1,574	677	2,997	5	**5,253**
Percent of Total	30%	13%	57%	0%	**100%**
Percent Proved Developed	98%	100%	99%	100%	**99%**
Percent Proved Undeveloped	2%	0%	1%	0%	**1%**
Production (Bcfe)	350	148	375	2	**875**
Capital Investments (millions)(2)	$ 204	$ 288	$ 86	$ 19	**$ 597**
Total Gross Producing Wells(3)	820	306	4,217	16	**5,359**
Total Net Producing Wells(3)	439	216	2,932	13	**3,600**
Total Net Acreage	245,805	321,563	918,535	3,023,386	**4,509,289**
Net Undeveloped Acreage	146,096	161,607	285,692	3,010,908	**3,604,303**

PV-10:										
Pre-Tax (millions)[4]	$	183	$	163	$	1,325	$	(6)	**$**	**1,665**
PV of Taxes (millions)[4]		–		–		–		–		**–**
After-Tax (millions)[4]	$	183	$	163	$	1,325	$	(6)	**$**	1,665
Percent of Total		11%		10%		79%		0%		**100%**
Percent Operated[5]		95%		100%		99%		100%		**98%**

(1) Other consists primarily of properties in Canada (which are subject to a moratorium), Colorado and Louisiana.

(2) Total and Other capital investments excludes $26 million related to our E&P service companies.

(3) Represents all producing wells, including wells in which we only have an overriding royalty interest, as of December 31, 2016.

(4) Pre-tax PV-10 (a non-GAAP measure) is one measure of the value of a company's proved reserves that we believe is used by securities analysts to compare relative values among peer companies without regard to income taxes. The reconciling difference in pre-tax PV-10 and the after-tax PV-10, or standardized measure, is the discounted value of future income taxes on the estimated cash flows from our proved natural gas, oil and NGL reserves.

(5) Based upon pre-tax PV-10 of proved developed producing activities.

The Company's 2016 and three-year average proved developed finding and development costs were $0.75 and $1.00 per Mcfe, respectively, when excluding the impact of capitalizing interest and portions of G&A costs in accordance with the full cost method of accounting.

Proved developed finding and development costs – Proved developed (PDP) finding and development (F&D) costs are computed here by dividing exploration and development capital costs incurred, excluding capitalized interest and expenses, for the indicated period by PDP reserve additions and proved undeveloped (PUD) conversions for that same period. At times, adjustments are made to this calculation in order to improve usefulness for investors. For example, adjustments are made to exclude the differences between accounting methods to improve comparability. The following computes PDP F&D costs for the periods ending December 31, 2016, 2015 and 2014 and the three years ending December 31, 2016. A breakdown is also shown detailing these amounts separately for Northeast Appalachia, Southwest Appalachia and the Fayetteville Shale.

TOTAL COMPANY PDP F&D

	12 Months Ended December 31, 2016	2015	2014	Three-Year Average 2016
Total PDP Adds (Bcfe):				
New PDP adds	257	416	531	1,204
PUD conversions	220	1,044	790	2,054
Total PDP Adds	**477**	**1,460**	**1,321**	**3,258**
Costs Incurred (in millions):				
Proved property acquisition costs	$ –	$ 81	$ 1,455	$ 1,536
Unproved property acquisition costs	171	692	3,934	4,797
Exploration costs	17	50	232	299
Development costs	433	1,417	1,600	3,450
Capitalized Costs Incurred	**$ 621**	**$ 2,240**	**$ 7,221**	**$ 10,082**
Subtract (in millions):				
Proved property acquisition costs	$ –	$ (81)	$ (1,455)	$ (1,536)
Unproved property acquisition costs	(171)	(692)	(3,934)	(4,797)
Capitalized interest and expense(1) associated with development and exploration	(91)	(187)	(206)	(484)
PDP Costs Incurred	**$ 359**	**$ 1,280**	**$ 1,626**	**$ 3,265**
PDP F&D	**$ 0.75**	**$ 0.88**	**$ 1.23**	**$ 1.00**

Note: Amounts may not add due to rounding

(1) Adjusting for the impacts of the full cost accounting method for comparability.

DIVISION PDP F&D

	12 Months Ended December 31, 2016				
	Appalachia		Fayetteville		
	Northeast	Southwest	Shale	Other	Total
Total PDP Adds (Bcfe):					
New PDP adds	81	157	19	–	257
PUD conversions	181	–	39	–	220
Total PDP Adds	**262**	**157**	**58**	**–**	**477**
Costs Incurred (in millions):					
Proved property acquisition costs	$ –	$ –	$ –	$ –	$ –
Unproved property acquisition costs	11	149	3	8	171
Exploration costs	8	8	1	–	17
Development costs	178	133	86	36	433
Capitalized Costs Incurred	**$ 197**	**$ 290**	**$ 90**	**$ 44**	**$ 621**
Subtract (in millions):					
Proved property acquisition costs	$ –	$ –	$ –	$ –	$ –
Unproved property acquisition costs	(11)	(149)	(3)	(8)	(171)
Capitalized interest and expense(1) associated with development and exploration	(31)	(28)	(21)	(11)	(91)
PDP Costs Incurred	**$ 155**	**$ 113**	**$ 66**	**$ 25**	**$ 359**
PDP F&D	**$ 0.59**	**$ 0.72**	**$ 1.14**	**$ –**	**$ 0.75**

Note: Amounts may not add due to rounding

(1) Adjusting for the impacts of the full cost accounting method for comparability.

The Company believes that providing a measure of PDP F&D costs is useful for investors as a means of evaluating a Company's cost to add proved reserves on a per thousand cubic feet of natural gas equivalent basis. These measures are provided in addition to, and not as an alternative for the financial statements, including the notes thereto, contained in Southwestern's Annual Report on Form 10-K. Due to various factors, including timing differences, PDP F&D costs do not necessarily reflect precisely the costs associated with particular reserves. Changes in commodity prices can affect the magnitude of recorded increases in reserves independent of the related costs of such increases. As a result of the foregoing factors and various factors that could materially affect the timing and amounts of future increases in reserves and the timing and amounts of future costs, including factors disclosed in Southwestern's filings with the SEC, future PDP F&D costs may differ materially from those set forth above. Further, the methods used by Southwestern to calculate its PDP F&D costs may differ significantly from methods used by other companies to compute similar measures and, as a result, Southwestern's PDP F&D costs may not be comparable to similar measures provided by other companies.

2016 Operational Review

During 2016, Southwestern invested a total of approximately $623 million in our E&P business, and participated in drilling 62 wells, completed 86 wells, placed 85 wells to sales and had 135 wells in progress. Of the 135 wells in progress at year-end, 73, 42 and 20 were located in our Northeast Appalachia, Southwest Appalachia and Fayetteville Shale operating areas, respectively, and 35 of these wells are waiting on pipeline or production facilities.

	For the years ended December 31,	
	2016	2015
E&P Capital Investments by Type	(in millions)	
Exploratory and development drilling, including workovers	$ **358**	$ 1,226
Acquisitions and leasehold	**23**	607
Seismic expenditures	**1**	6
Drilling rigs, sand facility and other	**2**	40
Capitalized interest and expense	**239**	379
Total E&P capital investments	$ **623**	$ 2,258
E&P Capital Investments by Area		
Northeast Appalachia	$ **165**	$ 652
Southwest Appalachia	**130**	659
Fayetteville Shale	**65**	496
New Ventures	**(2)**	48
E&P Services & Other	**26**	24
Capitalized interest and expense	**239**	379
Total E&P capital investments	$ **623**	$ 2,258

Year-end 2016 E&P Division Results

	Appalachia				Fayetteville Shale	
	Northeast		Southwest			
Production (Bcfe)		350		148		375
Gross operated production at year-end 2016 (Mmcfe/d)		1,138		577		1,377
Reserves:						
Reserves (Bcfe)		1,574		677		2,997
Capital investments ($ in millions)						
Exploratory and development drilling, including workovers	$	160	$	111	$	63
Acquisition and leasehold		3		18		2
Seismic and other		2		1		–
Capitalized interest and expense		39		158		21
Total capital investments	$	204	$	288	$	86
Gross operated well count summary						
Drilled		37		15		10
Completed		33		17		36
Wells to sales		24		18		43
Wells in progress		73		42		20
Year-end drilled uncompleted wells		46		40		13
Realized price						
NYMEX Henry Hub price ($/MMBtu)	$	2.46	$	2.46	$	2.46
Discount to NYMEX ($/Mcf)	$	(1.12)	$	(0.75)	$	(0.66)
Average realized gas price, excluding hedges ($/Mcf)	$	1.34	$	1.71	$	1.80

Northeast Appalachia – In the fourth quarter of 2016, the Company placed 12 wells to sales that had an average lateral length of 6,075 feet and an average cost of $4.7 million per well. The average rate for the first 30 days for wells online was 17,178 Mcf per day in the fourth quarter of 2016 compared to 4,796 Mcf per day in the fourth quarter of 2015. The stronger early rates are a result of increased completion intensity and optimized flow techniques implemented during the second half of the year. During the fourth quarter, Northeast Appalachia placed 11 wells to sales that were completed using increased completion intensity and optimized flow techniques, with all wells exhibiting encouraging early results. One example is the Cramer pad in Susquehanna County, where the Company brought five wells to sales in the fourth quarter with a cumulative rate of approximately 92 million cubic feet per day. Additionally, the Racine pad that was placed online in the third quarter of 2016 has continued to outperform offset wells, producing 75% more volumes in the first 125 days. While the Company continues to assess what portion of these increased volumes relate to incremental expected recovery and what portion relates to acceleration, these results clearly indicate additional value is being created with these new methods.

Additionally, the Company continued its delineation efforts in Tioga County, where initial infrastructure was installed, and it placed its first two well to sales in January 2017. The well results observed to date confirm the productivity of the acreage and the Company intends to further develop this area throughout 2017.

In 2016, Southwestern's operated horizontal wells had an average completed well cost of $5.3 million per well and an average horizontal lateral length of 6,142 feet. This compares to an average completed operated well cost of $5.4 million per well and an average horizontal lateral length of 5,403 feet in 2015.

As of December 31, 2016, Southwestern had spud or acquired 568 operated wells, of which 447 were horizontal and on production and 73 were in progress. Of the 447 operated horizontal wells on production, 281 were located in Susquehanna County, 140 were located in Bradford County, 25 were located in Lycoming County, and one was located in Wyoming County. Of the 73 wells in progress, 46 were either waiting on completion or waiting to be placed to sales, including 36 in Susquehanna County, six in Bradford County and four wells in Sullivan, Tioga and Wyoming Counties, combined.

Southwest Appalachia – In the fourth quarter of 2016, Southwestern brought online seven wells in Southwest Appalachia, including the Company's first drilled and completed Utica well, the O.E. Burge 501H. It was completed with a lateral length of 8,061 feet and is exhibiting the vast potential of this reservoir in the Company's Southwest Appalachia acreage. With the encouraging results, the Company accelerated the timeline for drilling its next Utica test well, which began drilling earlier this month.

Additionally, completion intensity testing continued during the quarter with increased amounts of proppant being used in some wells. In one group of wells, the Company tested one well using approximately 5,000 pounds per lateral foot of proppant and four wells using approximately 3,500 pounds per lateral foot, compared to the recent standard of 2,000 pounds per lateral foot. These wells, along with other test wells, have recently been placed online and early results are expected to be available at the end of the first quarter.

In 2016, of the 18 wells brought to sales, 15 were drilled and completed by Southwestern, of which 14 targeted the Marcellus Shale. The Marcellus wells had an average completed well cost of $5.4 million per well and an average horizontal lateral length of 5,316 feet. This compares to an average completed operated well cost of $6.9 million per well and an average horizontal lateral length of 6,985 feet in 2015.

The Company had a total of 299 horizontal and four vertical wells that the Company operated and that were on production as of December 31, 2016. Additionally, there were 42 horizontal wells in progress at the end of 2016, of which 20 were waiting on pipeline or production facilities.

Fayetteville Shale – During the fourth quarter of 2016, the Company placed 22 wells to sales with an average completed well cost of $2.8 million per well, and average horizontal lateral length of 5,547 feet. Of the 22 wells placed to sales, four were completed using increased proppant and tighter stage spacing. These new completion methods indicate improved initial well productivity and the Company will continue to evaluate additional results to optimize economic value.

During the fourth quarter of 2016, we continued delineation activity in the Moorefield, located just beneath the Fayetteville Shale. Eight Moorefield wells were drilled during the quarter, with seven of these being completed in the first quarter of 2017. These wells are expected to be placed to sales in March.

Explanation and Reconciliation of Non-GAAP Financial Measures

The Company reports its financial results in accordance with accounting principles generally accepted in the United States of America ("GAAP"). However, management believes certain non-GAAP performance measures may provide financial statement users with additional meaningful comparisons between current results, the results of its peers and of prior periods.

One such non-GAAP financial measure is net cash flow. Management presents this measure because (i) it is accepted 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, (ii) changes in operating assets and liabilities relate to the timing of cash receipts and disbursements which the Company may not control and (iii) changes in operating assets and liabilities may not relate to the period in which the operating activities occurred.

Additional non-GAAP financial measures the Company may present from time to time are net debt, adjusted net income, adjusted diluted earnings per share, adjusted EBITDA and its E&P and Midstream segment operating income, all which exclude certain charges or amounts. Management presents these measures because (i) they are consistent with the manner in which the Company's position and performance are measured relative to the position and performance of its peers, (ii) these measures are more comparable to earnings estimates provided by securities analysts, and (iii) charges or amounts excluded cannot be reasonably estimated and guidance provided by the Company excludes information regarding these types of items. These adjusted amounts are not a measure of financial performance under GAAP.

See the reconciliations throughout this release of GAAP financial measures to non-GAAP financial measures for the three and twelve months ended December 31, 2016 and December 31, 2015, as applicable. Non-GAAP financial measures should not be considered in isolation or as a substitute for the Company's reported results prepared in accordance with GAAP.

	3 Months Ended December 31,	
	2016	**2015**
	(in millions)	
Net income (loss) attributable to common stock:		
Net loss attributable to common stock	$ (237)	$ (2,134)
Add back:		
Participating securities - mandatory convertible preferred stock	(6)	–
Impairment of natural gas and oil properties	–	2,576
Restructuring and other one-time charges	12	–
Gain on sale of assets, net	–	(7)
Transaction costs	–	1
Loss on certain derivatives	324	50
Adjustments due to inventory valuation	–	32
Adjustments due to discrete tax items(1)	74	483
Tax impact on adjustments	(128)	(1,007)
Adjusted net income (loss) attributable to common stock	$ 39	$ (6)

(1) Primarily relates to the exclusion of certain discrete tax adjustments in the fourth quarter of 2016 due to an increase to the valuation allowance against the Company's deferred tax assets. The Company expects its 2017 income tax rate to be 38.0% before the impacts of any valuation allowance.

	3 Months Ended December 31,			
	2016		2015	
Diluted earnings (loss) per share:				
Diluted loss per share	$	(0.48)	$	(5.58)
Add back:				
Participating securities - mandatory convertible preferred stock		(0.01)		–
Impairment of natural gas and oil properties		–		6.74
Restructuring and other one-time charges		0.02		–
Gain on sale of assets, net		–		(0.02)
Transaction costs		–		0.00
Loss on certain derivatives		0.66		0.13
Adjustments due to inventory valuation		–		0.08
Adjustments due to discrete tax items(1)		0.15		1.26
Tax impact on adjustments		(0.26)		(2.63)
Adjusted diluted earnings (loss) per share	$	0.08	$	(0.02)

(1) Primarily relates to the exclusion of certain discrete tax adjustments in the fourth quarter of 2016 due to an increase to the valuation allowance against the Company's deferred tax assets. The Company expects its 2017 income tax rate to be 38.0% before the impacts of any valuation allowance.

	12 Months Ended December 31,			
	2016		2015	
	(in millions)			
Net income (loss) attributable to common stock:				
Net loss attributable to common stock	$	(2,751)	$	(4,662)
Add back:				
Participating securities – mandatory convertible preferred stock		–		(13)
Impairment of natural gas and oil properties		2,321		6,950
Restructuring and other one-time charges		89		2
Gain on sale of assets, net		(3)		(283)
Loss on early extinguishment of debt and other(1)		57		–
Transaction costs		–		54
Loss on certain derivatives		373		155
Adjustments due to inventory valuation		3		32
Adjustments due to discrete tax items(2)		978		483
Tax impact on adjustments		(1,074)		(2,647)
Adjusted net income (loss) attributable to common stock	$	(7)	$	71

(1) Includes a $51 million loss for the redemption of certain senior notes and a $6 million loss related to the unamortized debt issuance costs and debt discounts associated with the extinguished debt which were included in other interest charges.

(2) Primarily relates to the exclusion of certain discrete tax adjustments due to an increase to the valuation allowance against the Company's deferred tax assets. The Company expects its 2017 income tax rate to be 38.0% before the impacts of any valuation allowance.

	12 Months Ended December 31,	
	2016	**2015**
Diluted earnings (loss) per share:		
Diluted loss per share	$ (6.32)	$ (12.25)
Add back:		
Participating securities – mandatory convertible preferred stock	–	(0.03)
Impairment of natural gas and oil properties	5.33	18.26
Restructuring and other one-time charges	0.20	0.01
Gain on sale of assets, net	(0.00)	(0.74)
Loss on early extinguishment of debt and other(1)	0.13	–
Transaction costs	–	0.14
Loss on certain derivatives	0.86	0.41
Adjustments due to inventory valuation	0.01	0.08
Adjustments due to discrete tax items(2)	2.25	1.27
Tax impact on adjustments	(2.47)	(6.96)
Adjusted diluted earnings (loss) per share	$ (0.01)	$ 0.19

(1) Includes a $51 million loss for the redemption of certain senior notes and a $6 million loss related to the unamortized debt issuance costs and debt discounts associated with the extinguished debt which were included in other interest charges.

(2) Primarily relates to the exclusion of certain discrete tax adjustments due to an increase to the valuation allowance against the Company's deferred tax assets. The Company expects its 2017 income tax rate to be 38.0% before the impacts of any valuation allowance.

	3 Months Ended December 31,	
	2016	**2015**
	(in millions)	
Cash flow from operating activities:		
Net cash provided by operating activities	$ 161	$ 353
Add back:		
Changes in operating assets and liabilities	49	(47)
Restructuring charges	1	–
Net cash flow	$ 211	$ 306

	12 Months Ended December 31,	
	2016	**2015**
	(in millions)	
Cash flow from operating activities:		
Net cash provided by operating activities	$ 498	$ 1,580
Add back:		
Changes in operating assets and liabilities	99	(112)
Restructuring charges	48	–
Net cash flow	$ 645	$ 1,468

	3 Months Ended December 31,	
	2016	**2015**
	(in millions)	
Operating income (loss):		
Operating income (loss)	$ 122	$ (2,561)
Add back:		
Impairment of natural gas and oil properties	–	2,576
Gain on sale of assets, net	–	(7)
Restructuring and other one-time charges	12	–
Adjusted operating income	$ 134	$ 8

	12 Months Ended December 31,	
	2016	2015
	(in millions)	
Operating income (loss):		
Operating loss	$ (2,195)	$ (6,522)
Add back:		
Impairment of natural gas and oil properties	2,321	6,950
Gain on sale of assets, net	–	(283)
Restructuring and other one-time charges	89	1
Adjusted operating income	$ 215	$ 146

	3 Months Ended December 31,	
	2016	2015
	(in millions)	
E&P segment operating income (loss):		
E&P segment operating income (loss)	$ 82	$ (2,633)
Add back:		
Impairment of natural gas and oil properties	–	2,576
Gain on sale of assets, net	–	(7)
Restructuring and other one-time charges	12	–
Adjusted E&P segment operating income (loss)	$ 94	$ (64)

	12 Months Ended December 31,	
	2016	2015
	(in millions)	
E&P segment operating income (loss):		
E&P segment operating loss	$ (2,404)	$ (7,104)
Add back:		
Impairment of natural gas and oil properties	2,321	6,950
Gain on sale of assets, net	–	(6)
Restructuring and other one-time charges	86	1
Adjusted E&P segment operating income (loss)	$ 3	$ (159)

	12 Months Ended December 31,	
	2016	2015
	(in millions)	
Midstream segment operating income:		
Midstream segment operating income	$ 209	$ 583
Add back:		
Restructuring charges	3	–
Gain on sale of assets, net	–	(277)
Adjusted Midstream segment operating income	$ 212	$ 306

	December 31,	
	2016	2015
	(in millions)	
Net debt:		
Total debt	$ 4,653	$ 4,705
Subtract:		
Cash and cash equivalents	(1,423)	(15)
Net debt	$ 3,230	$ 4,690

Southwestern management will host a teleconference call on Friday, February 24, 2016 at 10:00 a.m. Eastern to discuss its fourth quarter and year-end 2016 results. The toll-free number to call is 877-407-8035 and the international dial-in number is 201-689-8035. The teleconference can also be heard “live” on the Internet at http://www.swn.com.

Southwestern Energy Company is an independent energy company whose wholly-owned subsidiaries are engaged in natural gas and oil exploration, development and production, natural gas gathering and marketing. Additional information on the Company can be found on the Internet at http://www.swn.com.

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This news release contains forward-looking statements. Forward-looking statements relate to future events and anticipated results of operations, business strategies, and other aspects of our operations or operating results. In many cases you can identify forward-looking statements by terminology such as “anticipate,” “intend,” “plan,” “project,” “estimate,” “continue,” “potential,” “should,” “could,” “may,” “will,” “objective,” “guidance,” “outlook,” “effort,” “expect,” “believe,” “predict,” “budget,” “projection,” “goal,” “forecast,” “target” or similar words. Statements may be forward looking even in the absence of these particular words. Where, in any forward-looking statement, the Company expresses an expectation or belief as to future results, such expectation or belief is expressed in good faith and believed to have a reasonable basis. However, there can be no assurance that such expectation or belief will result or be achieved. The actual results of operations can and will be affected by a variety of risks and other matters including, but not limited to, changes in commodity prices; changes in expected levels of natural gas and oil reserves or production; operating hazards, drilling risks, unsuccessful exploratory activities; limited access to capital or significantly higher cost of capital related to illiquidity or uncertainty in the domestic or international financial markets; international monetary conditions; unexpected cost increases; potential liability for remedial actions under existing or future environmental regulations; potential liability resulting from pending or future litigation; and general domestic and international economic and political conditions; as well as changes in tax, environmental and other laws applicable to our business. Other factors that could cause actual results to differ materially from those described in the forward-looking statements include other economic, business, competitive and/or regulatory factors affecting our business generally as set forth in our filings with the Securities and Exchange Commission. Unless legally required, Southwestern Energy Company undertakes no obligation to update publicly any forward-looking statements, whether as a result of new information, future events or otherwise.

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OPERATING STATISTICS (Unaudited)
Southwestern Energy Company and Subsidiaries

	For the three months ended December 31,				For the years ended December 31,			
	2016		2015		**2016**		2015	
Exploration & Production								
Production								
Gas production (Bcf)		**183**		226		**788**		899
Oil production (MBbls)		**463**		569		**2,192**		2,265
NGL production (MBbls)		**2,792**		3,328		**12,372**		10,702
Total production (Bcfe)		**202**		249		**875**		976
Commodity Prices								
Average realized gas price per Mcf, including derivatives	**$**	**2.07**	$	2.07	**$**	**1.64**	$	2.37
Average realized gas price per Mcf, excluding derivatives	**$**	**2.00**	$	1.48	**$**	**1.59**	$	1.91
Average realized oil price per Bbl	**$**	**41.18**	$	27.36	**$**	**31.20**	$	33.25
Average realized NGL price per Bbl	**$**	**12.08**	$	7.62	**$**	**7.46**	$	6.80
Summary of Derivative Activity in the Statement of Operations								
Settled commodity amounts included in "Operating Revenues" (in millions)	**$**	**–**	$	64	**$**	**–**	$	209
Settled commodity amounts included in "Gain (Loss) on Derivatives" (in millions)	**$**	**14**	$	69	**$**	**36**	$	206
Unsettled commodity amounts included in "Gain (Loss) on Derivatives" (in millions)	**$**	**(330)**	$	(50)	**$**	**(375)**	$	(153)
Average unit costs per Mcfe								
Lease operating expenses	**$**	**0.87**	$	0.91	**$**	**0.87**	$	0.92
General & administrative expenses (1)	**$**	**0.27**	$	0.20	**$**	**0.22**	$	0.21
Taxes, other than income taxes (2)	**$**	**0.11**	$	0.09	**$**	**0.10**	$	0.10
Full cost pool amortization	**$**	**0.30**	$	0.78	**$**	**0.38**	$	1.00
Midstream								
Volumes marketed (Bcfe)		**248**		290		**1,062**		1,127
Volumes gathered (Bcf)		**138**		179		**601**		799

(1) Excludes $12 million and $83 million of restructuring and other one-time charges for the three months and year ended December 31, 2016, respectively.

(2) Excludes $3 million of restructuring charges for the year ended December 31, 2016.

STATEMENTS OF OPERATIONS (Unaudited)
Southwestern Energy Company and Subsidiaries

	For the three months ended December 31,		For the years ended December 31,	
	2016	2015	**2016**	2015
	(in millions, except share/per share amounts)			
Operating Revenues				
Gas sales	**$ 367**	$ 406	**$ 1,273**	$ 1,946
Oil sales	**19**	16	**69**	76
NGL sales	**33**	26	**92**	73
Marketing	**233**	200	**864**	863
Gas gathering	**32**	39	**138**	175
	684	687	**2,436**	3,133
Operating Costs and Expenses				
Marketing purchases	**237**	198	**864**	852
Operating expenses	**137**	182	**592**	689
General and administrative expenses	**76**	58	**247**	246
Restructuring charges	**1**	–	**78**	–
Depreciation, depletion and amortization	**87**	215	**436**	1,091
Impairment of natural gas and oil properties	**–**	2,576	**2,321**	6,950
Gain on sale of assets, net	**–**	(7)	**–**	(283)
Taxes, other than income taxes	**24**	26	**93**	110
	562	3,248	**4,631**	9,655
Operating Income (Loss)	**122**	(2,561)	**(2,195)**	(6,522)
Interest Expense				
Interest on debt	**58**	47	**226**	200
Other interest charges	**2**	6	**14**	60
Interest capitalized	**(29)**	(49)	**(152)**	(204)
	31	4	**88**	56
Gain (Loss) on Derivatives	**(311)**	17	**(339)**	47
Loss on Early Extinguishment of Debt	**–**	–	**(51)**	–
Other Income (Loss), Net	**1**	(32)	**1**	(30)
Loss Before Income Taxes	**(219)**	(2,580)	**(2,672)**	(6,561)
Income Tax Benefit				
Current	**(7)**	(9)	**(7)**	(2)
Deferred	**(2)**	(464)	**(22)**	(2,003)
	(9)	(473)	**(29)**	(2,005)
Net Loss	**(210)**	(2,107)	**(2,643)**	(4,556)
Mandatory convertible preferred stock dividend	**27**	27	**108**	106
Net Loss Attributable to Common Stock	**$ (237)**	$ (2,134)	**$ (2,751)**	$ (4,662)
Loss Per Common Share				
Basic	**$ (0.48)**	$ (5.58)	**$ (6.32)**	$ (12.25)
Diluted	**$ (0.48)**	$ (5.58)	**$ (6.32)**	$ (12.25)
Weighted Average Common Shares Outstanding				
Basic	**489,287,827**	382,334,978	**435,337,402**	380,521,039
Diluted	**489,287,827**	382,334,978	**435,337,402**	380,521,039

BALANCE SHEETS (Unaudited)
Southwestern Energy Company and Subsidiaries

	December 31, 2016	December 31, 2015
	(in millions)	
ASSETS		
Current assets	**$ 1,872**	$ 393
Property and equipment	**24,489**	24,364
Less: Accumulated depreciation, depletion and amortization	**(19,534)**	(16,821)
Total property and equipment, net	**4,955**	7,543
Other long-term assets	**249**	150
Total assets	**7,076**	8,086
LIABILITIES AND EQUITY		
Current liabilities	**1,064**	707
Long-term debt	**4,612**	4,704
Pension and other postretirement liabilities	**49**	50
Other long-term liabilities	**434**	343
Total liabilities	**6,159**	5,804
Equity:		
Common stock, $0.01 par value; 1,250,000,000 shares authorized; issued 495,248,369 shares as of December 31, 2016 (does not include 2,751,410 shares issued on January 17, 2017 on account of a dividend declared on December 12, 2016) and 390,138,549 as of December 31, 2015	**5**	4
Preferred stock, $0.01 par value, 10,000,000 shares authorized, 6.25% Series B Mandatory Convertible, $1,000 per share liquidation preference, 1,725,000 shares issued and outstanding as of December 31, 2016 and 2015, conversion in January 2018	**–**	–
Additional paid-in capital	**4,677**	3,409
Accumulated deficit	**(3,725)**	(1,082)
Accumulated other comprehensive loss	**(39)**	(48)
Common stock in treasury; 31,269 shares as of December 31, 2016 and 47,149 as of December 31, 2015, respectively	**(1)**	(1)
Total equity	**917**	2,282
Total liabilities and equity	**$ 7,076**	$ 8,086

STATEMENTS OF CASH FLOWS (Unaudited)

Southwestern Energy Company and Subsidiaries

	For the years ended December 31, 2016	2015
	(in millions)	
Cash Flows From Operating Activities:		
Net loss	**$ (2,643)**	$ (4,556)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	**436**	1,092
Impairment of natural gas and oil properties	**2,321**	6,950
Amortization of debt issuance costs	**14**	53
Deferred income taxes	**(22)**	(2,003)
Loss on derivatives, net of settlement	**373**	155
Stock-based compensation	**29**	26
Gain on sales of assets, net	**–**	(283)
Restructuring charges	**30**	–
Loss on early extinguishment of debt	**51**	–
Other	**8**	34
Change in assets and liabilities	**(99)**	112
Net cash provided by operating activities	**498**	1,580
Cash Flows From Investing Activities:		
Capital investments	**(593)**	(1,798)
Acquisitions	**–**	(579)
Proceeds from sale of property and equipment	**430**	729
Other	**1**	10
Net cash used in investing activities	**(162)**	(1,638)
Cash Flows From Financing Activities:		
Payments on current portion of long-term debt	**(1)**	(1)
Payments on long-term debt	**(1,175)**	(500)
Payments on short-term debt	**–**	(4,500)
Payments on revolving credit facility	**(3,268)**	(3,024)
Borrowings under revolving credit facility	**3,152**	2,840
Payments on commercial paper	**(242)**	(7,988)
Borrowings under commercial paper	**242**	7,988
Change in bank drafts outstanding	**(20)**	12
Proceeds from issuance of long-term debt	**1,191**	2,950
Debt issuance costs	**(17)**	(20)
Proceeds from issuance of common stock	**1,247**	669
Proceeds from issuance of mandatory convertible preferred stock	**–**	1,673
Preferred stock dividend	**(27)**	(79)
Cash paid for tax withholding	**(9)**	–
Other	**(1)**	–
Net cash provided by financing activities	**1,072**	20
Increase (decrease) in cash and cash equivalents	**1,408**	(38)
Cash and cash equivalents at beginning of year	**15**	53
Cash and cash equivalents at end of year	**$ 1,423**	$ 15

SEGMENT INFORMATION (Unaudited)

Southwestern Energy Company and Subsidiaries

	Exploration and Production	Midstream Services	Other	Eliminations	Total
			(in millions)		
Three months ended December 31, 2016					
Revenues	**$ 415**	**$ 707**	**$ –**	**$ (438)**	**$ 684**
Marketing purchases	**–**	**612**	**–**	**(375)**	**237**
Operating expenses	**175**	**25**	**–**	**(63)**	**137**
General and administrative expenses	**63**	**13**	**–**	**–**	**76**
Restructuring charges	**1**	**–**	**–**	**–**	**1**
Depreciation, depletion and amortization	**71**	**16**	**–**	**–**	**87**
Taxes, other than income taxes	**23**	**1**	**–**	**–**	**24**
Operating income	**82**	**40**	**–**	**–**	**122**
Capital investments [(1)]	**251**	**18**	**3**	**–**	**272**
Three months ended December 31, 2015					
Revenues	$ 441	$ 668	$ (1)	$ (421)	$ 687
Marketing purchases	–	541	–	(343)	198
Operating expenses	229	33	(2)	(78)	182
General and administrative expenses	49	9	–	–	58
Depreciation, depletion and amortization	204	10	1	–	215
Impairment of natural gas and oil properties	2,576	–	–	–	2,576
Gain on sale of assets, net	(7)	–	–	–	(7)
Taxes, other than income taxes	23	3	–	–	26
Operating income (loss)	(2,633)	72	–	–	(2,561)
Capital investments [(1)]	378	3	2	–	383
Year ended December 31, 2016					
Revenues	**$ 1,413**	**$ 2,569**	**$ –**	**$ (1,546)**	**$ 2,436**
Marketing purchases	**–**	**2,145**	**–**	**(1,281)**	**864**
Operating expenses	**761**	**96**	**–**	**(265)**	**592**
General and administrative expenses	**204**	**43**	**–**	**–**	**247**
Restructuring charges	**75**	**3**	**–**	**–**	**78**
Depreciation, depletion and amortization	**371**	**65**	**–**	**–**	**436**
Impairment of natural gas and oil properties	**2,321**	**–**	**–**	**–**	**2,321**
Taxes, other than income taxes	**85**	**8**	**–**	**–**	**93**
Operating income (loss)	**(2,404)**	**209**	**–**	**–**	**(2,195)**
Capital investments [(1)]	**623**	**21**	**4**	**–**	**648**
Year ended December 31, 2015					
Revenues	$ 2,074	$ 3,119	$ –	$ (2,060)	$ 3,133
Marketing purchases	–	2,566	–	(1,714)	852
Operating expenses	899	136	–	(346)	689
General and administrative expenses	207	39	–	–	246
Depreciation, depletion and amortization	1,028	62	1	–	1,091
Impairment of natural gas and oil properties	6,950	–	–	–	6,950
Gain on sale of assets, net	(6)	(277)	–	–	(283)
Taxes, other than income taxes	100	10	–	–	110
Operating income (loss)	(7,104)	583	(1)	–	(6,522)
Capital investments [(1)]	2,258	167	12	–	2,437

(1) Capital investments includes an increase of $67 million and a decrease of $28 million for the three months ended December 31, 2016 and 2015, respectively, and an increase of $43 million and a decrease of $33 million for the years ended December 31, 2016 and 2015, respectively, relating to the change in accrued expenditures between periods.