UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of the

Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): February 22, 2018

Unit Corporation

Unit Corporation

(Exact name of registrant as specified in its charter)

Delaware	1-9260	73-1283193
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

8200 South Unit Drive, Tulsa, Oklahoma	74132
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (918) 493-7700

Not Applicable
(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

[ ] Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

[ ] Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

[ ] Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

[ ] Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

Emerging growth company [ ]

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. [ ]

Section 2 - Financial Information.

Item 2.02 Results of Operations and Financial Condition.

On February 22, 2018, the Company issued a press release announcing its financial results for the three and twelve month periods ending December 31, 2017. The Company is making reference to non-GAAP financial measures in the press release. A reconciliation of these non-GAAP financial measures to the comparable GAAP financial measures is contained in the attached press release.

A copy of that release is furnished with this filing as Exhibit 99.1.

The information included in this report and in exhibit 99.1 shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the Exchange Act), or incorporated by reference in any filing under the Securities Act of 1933, as amended (the Securities Act), or the Exchange Act, except as expressly set forth by specific reference in the filing.

The press release furnished as an exhibit to this report contains forward-looking statements within the meaning of the Securities Act and the Exchange Act. Those forward-looking statements are subject to certain risks and uncertainties, as disclosed by the Company occasionally in its filings with the Securities and Exchange Commission. Because of these risks, the Company's actual results may differ materially from those indicated or implied by the forward-looking statements. Except as required by law, we disclaim any obligation to publicly update or revise forward looking statements after the date of this report to conform them to actual results.

Section 9 - Financial Statements and Exhibits.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits.

99.1 Press release dated February 22, 2018

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

Unit Corporation

Date: February 22, 2018

By: /s/ Les Austin

Les Austin
Senior Vice President and Chief Financial Officer

EXHIBIT INDEX

Exhibit No.	Description
99.1	Press release dated February 22, 2018

News

UNIT CORPORATION

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For Immediate Release…
February 22, 2018

UNIT CORPORATION REPORTS 2017 FOURTH QUARTER AND YEAR END RESULTS

Tulsa, Oklahoma . . . Unit Corporation (NYSE - UNT) today reported its financial and operational results for the fourth quarter and year end 2017. Fourth quarter and year end highlights include:

- Fourth quarter net income of $89.2 million, which reflects an $81.3 million net tax benefit related to tax legislation enacted in the quarter, and adjusted net income of $11.3 million.
- Oil and natural gas segment production increased 6% over the third quarter of 2017.
- Total year-end 2017 proved oil and natural gas reserves increased 27% over 2016.
- Replaced 300% of 2017 production with new reserves.
- Contract drilling segment placed its 10th BOSS rig into service in 2017; all ten BOSS rigs continuously operated under contract during the year.
- Average drilling rigs used in 2017 increased 72% over 2016.
- Midstream segment increased liquids sold and gas processed volumes 10% and 6%, respectively, over the third quarter.

FOURTH QUARTER AND YEAR END 2017 FINANCIAL RESULTS

Unit recorded net income of $89.2 million for the quarter, or $1.71 per diluted share, compared to net income of $1.7 million, or $0.03 per share, for the fourth quarter of 2016. Net income for the quarter included an $81.3 million income tax benefit associated with the revaluation of the net deferred tax liability due to the Tax Cuts and Jobs Act (the Tax Act) enacted during the quarter by the U.S. government. Adjusted net income (which excludes the effect of non-cash commodity derivatives and the effect of the Tax Act) for the quarter was $11.3 million, or $0.22 per diluted share (see Non-GAAP financial measures below). Total revenues for the quarter were $204.8 million (49% oil and natural gas, 23% contract drilling, and 28% midstream), compared to $174.3 million (51% oil and natural gas, 19% contract drilling, and 30% midstream) for the fourth quarter of 2016. Adjusted EBITDA was $91.2 million, or $1.75 per diluted share (see Non-GAAP financial measures below).

For 2017, Unit recorded net income of $117.8 million, or $2.28 per diluted share, compared to a net loss of $135.6 million, or a loss of $2.71 per share, for 2016. Net income for the year included the $81.3 million income tax benefit associated with the revaluation of the net deferred tax liability due to the Tax Act. Unit recorded adjusted net income (which excludes the effect of non-cash commodity derivatives and the effect of the Tax Act) of $27.7 million, or $0.54 per diluted share (see Non-GAAP financial measures below). Total revenues for the year were $739.6 million (48% oil and natural gas, 24% contract drilling, and 28% midstream), compared to $602.2 million (49% oil and natural gas, 20% contract drilling, and 31% midstream) for 2016. Adjusted EBITDA for 2017 was $315.7 million, or $6.10 per diluted share (see Non-GAAP financial measures below).

OIL AND NATURAL GAS SEGMENT INFORMATION

For the quarter, total equivalent production was 4.3 million barrels of oil equivalent (MMBoe), a 6% increase over the third quarter of 2017. Oil and natural gas liquids (NGLs) production represented 46% of total equivalent production. Oil production was 7,877 barrels per day. NGLs production was 13,713 barrels per day. Natural gas production was 151.6 million cubic feet (MMcf) per day. Total production for 2017 was 16.0 MMBoe, a 7% decrease from 2016.

Unit’s average realized per barrel equivalent price for the quarter was $23.25, a 13% increase over the third quarter of 2017. Unit’s average natural gas price was $2.38 per Mcf, an increase of 1% over the third quarter of 2017. Unit’s average oil price was $54.45 per barrel, an increase of 15% over the third quarter of 2017. Unit’s average NGLs price was $21.88 per barrel, an increase of 19% over the third quarter of 2017. All prices in this paragraph include the effects of derivative contracts.

In the Wilcox area, Unit continued its exploration and recompletion programs during the quarter. In the Cherry Creek prospect, production from the Trinity #1 well was brought online with an initial 30-day production (IP30) rate of 6 MMcfe per day. The Trinity is a discovery well with several additional zones to be developed. Unit is planning to drill the second well in the prospect later in 2018. In the Brandt prospect, Unit successfully drilled and completed a new discovery well, the Engel #1, with an IP30 rate of 8.3 MMcfe per day. In addition, there were 10 new behind pipe recompletions, increasing combined production for those wells 16 MMcf per day and 500 barrels of oil per day at a cost of $3 million. Unit's plan for 2018 is for 13-15 recompletions and 10 new wells (8 vertical and 2 horizontal).

In the Texas Panhandle Granite Wash area, during the quarter, Unit completed the Dixon 5554 CXL #5H well and the Dixon 5554 CXL #6H well. The Dixon 5554 CXL #6H is Unit's first extended length lateral well targeting the B interval of the Granite Wash and had an IP30 rate of 9.4 MMcfe per day, which is above type curve expectations. Unit also drilled three of its longest laterals to date, which range from 8,700 feet to 9,700 feet, targeting the C1 interval of the Granite Wash. The three wells were completed in January and are in the early stages of flowing back. Unit's plan is to continuously operate at least one drilling rig in the Granite Wash during 2018, which is planned to result in 11 new extended length lateral wells.

In the Southern Oklahoma Hoxbar Oil Trend (SOHOT) area, during the quarter, Unit completed two new Marchand horizontal wells. Production for both wells was brought online in late November. The Nina #1-22H had an IP30 rate of 1,114 Boe per day and the Schmidt #1-10H had an IP30 rate of 691 Boe per day, both of which are above type curve expectations. Unit began drilling its first extended lateral Marchand well, the Schenk Trust 1-17HXL, in late November. Production from this well was brought online in late January with strong results at an IP20 rate of 2,468 Boe per day. During 2018, Unit plans to continue with a one rig drilling program, which should result in nine new wells, with six being extended lateral wells.

In western Oklahoma, Unit owns approximately 17,000 net acres in the STACK play. Unit continues its effort to acquire and concentrate its acreage position to facilitate horizontal well development, and Unit plans to initiate drilling in this area during the first quarter of 2018.

Larry Pinkston, Unit’s Chief Executive Officer and President, said: "Our oil and natural gas segment had its third consecutive quarter of production growth. We are very pleased to be on a solid production growth trajectory. We continue to be encouraged by the results in each of our three core areas. All three have provided rates of return that compare favorably with other active basins."

This table illustrates certain comparative production, realized prices, and operating profit for the periods indicated:

	Three Months Ended				Three Months Ended				Twelve Months Ended		
	Dec 31, 2017	Dec 31, 2016	Change		Dec 31, 2017	Sept 30, 2017	Change		Dec 31, 2017	Dec 31, 2016	Change
Oil and NGLs Production, MBbl	1,986	1,983	—%		1,986	1,876	6%		7,453	7,988	(7)%
Natural Gas Production, Bcf	13.9	13.4	4%		13.9	13.1	7%		51.3	55.7	(8)%
Production, MBoe	4,310	4,209	2%		4,310	4,057	6%		15,996	17,277	(7)%
Production, MBoe/day	46.8	45.8	2%		46.8	44.1	6%		43.8	47.2	(7)%
Avg. Realized Natural Gas Price, Mcf (1)	$ 2.38	$ 2.37	—%		$ 2.38	$ 2.36	1%		$ 2.46	$ 2.07	19%
Avg. Realized NGL Price, Bbl (1)	$ 21.88	$ 14.57	50%		$ 21.88	$ 18.35	19%		$ 18.35	$ 11.26	63%
Avg. Realized Oil Price, Bbl (1)	$ 54.45	$ 46.14	18%		$ 54.45	$ 47.29	15%		$ 49.44	$ 40.50	22%
Realized Price / Boe (1)	$ 23.25	$ 19.73	18%		$ 23.25	$ 20.63	13%		$ 21.72	$ 16.92	28%
Operating Profit Before Depreciation, Depletion, Amortization & Impairment (MM) (2)	$ 66.6	$ 60.4	10%		$ 66.6	$ 51.6	29%		$ 227.0	$ 174.0	30%

(1) Realized price includes oil, NGLs, natural gas, and associated derivatives.

(2) Operating profit before depreciation is calculated by taking operating revenues for this segment less operating expenses excluding depreciation, depletion, amortization, and impairment. (See Non-GAAP financial measures below.)

YEAR END 2017 ESTIMATED PROVED RESERVES

The discount rate (PV-10) value of Unit's estimated year end 2017 proved reserves increased 56% over 2016 to $897.5 million. Estimated year end 2017 proved oil and natural gas reserves were 149.8 MMBoe, or 898.6 billion cubic feet of natural gas equivalents (Bcfe), as compared with 117.8 MMBoe, or 706.6 Bcfe, at year end 2016, a 27% increase. Estimated reserves were 13% oil, 30% NGLs, and 57% natural gas.

The following details the changes to Unit's proved oil, NGLs, and natural gas reserves during 2017:

	Oil (MMbls)	NGLs (MMbls)	Natural Gas (Bcf)	Proved Reserves (MMBoe)
Proved Reserves, at December 31, 2016	15.7	34.5	405.6	117.8
Revisions of previous estimates	0.7	4.3	38.4	11.4
Extensions, discoveries, and other additions	3.9	10.3	101.6	31.1
Purchases of minerals in place	2.0	1.2	15.3	5.8
Production	(2.7)	(4.7)	(51.3)	(16.0)
Sales	(0.1)	(0.1)	(0.9)	(0.3)
Proved Reserves, at December 31, 2017	19.5	45.5	508.7	149.8

Estimated 2017 year-end proved reserves included proved developed reserves of 113.0 MMBoe, or 677.8 Bcfe, (13% oil, 30% NGLs, and 57% natural gas) and proved undeveloped reserves of 36.8 MMBoe, or 220.9 Bcfe, (13% oil, 33% NGLs, and 54% natural gas). Overall, 75% of the estimated proved reserves are proved developed.

The present value of the estimated future net cash flows from 2017 estimated proved reserves (before income taxes and using a PV-10), is approximately $897.5 million. The present value was determined using the required SEC's pricing methodology. The aggregate price used for all future reserves was $51.34 per barrel of oil, $31.83 per barrel of NGLs, and $2.98 per Mcf of natural gas (then adjusted for price differentials). Unit's 2017 year-end proved reserves were independently audited by Ryder Scott Company, L.P. Their audit covered properties accounting for 86% of the discounted future net cash flow (PV-10). See below for the reconciliation of PV-10 to the Standardized Measure of discounted future net cash flows as defined by GAAP.

Pinkston said: "Our goal is to replace at least 150% of each year's production with new reserves. In 2017, we achieved our goal by replacing 300% of production with new reserves, our second highest production replacement percentage in the last 15 years. We achieved this growth while maintaining a capital expenditure program in line with cash flow."

CONTRACT DRILLING SEGMENT INFORMATION

Unit's average number of drilling rigs working during the quarter was 31.2, a decrease of 10% from the third quarter of 2017. Per day drilling rig rates averaged $16,645, a 1% increase over the third quarter of 2017. Average per day operating margin for the quarter was $5,550 (before elimination of intercompany drilling rig profit of $0.6 million). This compares to third quarter 2017 average operating margin of $5,495 (before elimination of intercompany drilling rig profit of $0.6 million), an increase of 1%, or $55.

Pinkston said: "Our contract drilling segment's level of utilization grew through the third quarter to a high of 36 operating rigs. Utilization pared back in the fourth quarter as operators approached the limits of their 2017 capital budgets. We have 95 drilling rigs in our fleet after adding our tenth BOSS rig during the second quarter. All 10 of our BOSS rigs are under contract, and we currently have a total of 32 drilling rigs operating. Long-term contracts (contracts with original terms ranging from six months to two years in length) are in place for nine of our drilling rigs. Of the nine contracts, four are up for renewal in the first quarter of 2018, three in the second quarter, one in the fourth quarter and one in 2019."

This table illustrates certain comparative results for the periods indicated:

	Three Months Ended			Three Months Ended			Twelve Months Ended		
	Dec 31, 2017	**Dec 31, 2016**	**Change**	**Dec 31, 2017**	**Sept 30, 2017**	**Change**	**Dec 31, 2017**	**Dec 31, 2016**	**Change**
Rigs Utilized	31.2	19.5	60%	31.2	34.6	(10)%	30.0	17.4	72%
Operating Profit Before Depreciation (MM) (1)	$ 15.3	$ 11.6	31%	$ 15.3	$ 16.9	(9)%	$ 52.1	$ 33.9	54%

(1) Operating profit before depreciation is calculated by taking operating revenues for this segment less operating expenses excluding depreciation. (See Non-GAAP financial measures below.)

MIDSTREAM SEGMENT INFORMATION

For the quarter, gas processed and liquids sold volumes per day increased 6% and 10%, respectively, while gas gathered volumes per day remained relatively unchanged, as compared to the third quarter of 2017. Operating profit (as defined in the footnote below) for the quarter was $13.1 million, a decrease of 2% from the third quarter of 2017.

For 2017, per day gas gathered and gas processed volumes decreased 8% and 11%, respectively, while liquids sold volumes remained relatively unchanged as compared to 2016. Operating profit (as defined in the footnote below) for 2017 was $51.7 million, an increase of 7% over 2016.

This table illustrates certain comparative results for the periods indicated:

	Three Months Ended			Three Months Ended			Twelve Months Ended		
	Dec 31, 2017	**Dec 31, 2016**	**Change**	**Dec 31, 2017**	**Sept 30, 2017**	**Change**	**Dec 31, 2017**	**Dec 31, 2016**	**Change**
Gas Gathering, Mcf/day	383,319	423,669	(10)%	383,319	383,787	—%	385,209	419,217	(8)%
Gas Processing, Mcf/day	148,422	140,719	5%	148,422	140,246	6%	137,625	155,461	(11)%
Liquids Sold, Gallons/day	581,874	535,253	9%	581,874	530,028	10%	534,140	536,494	—%
Operating Profit Before Depreciation and Amortization (MM) (1)	$ 13.1	$ 14.7	(11)%	$ 13.1	$ 13.3	(2)%	$ 51.7	$ 48.3	7%

(1) Operating profit before depreciation is calculated by taking operating revenues for this segment less operating expenses excluding depreciation and amortization. (See Non-GAAP financial measures below.)

Pinkston said: "Our midstream segment operated in ethane rejection mode during the quarter at all processing facilities except Bellmon and Cashion, where it is more beneficial to recover under the existing contracts. Processing and liquids sold volumes reflected quarter over quarter improvement due to increasing processing volumes at the Hemphill and Cashion facilities. Overall, our midstream segment continues to post solid results as operator activity levels increase; in fact, we set a new record operating profit before depreciation and amortization for the year."

2018 CAPITAL BUDGET AND PRODUCTION GUIDANCE

Pinkston said: "The outlook for commodity prices continues to be volatile. We continue to be diligent with our capital expenditure plans to maintain our spending in line with anticipated cash flow plus any proceeds derived from non-core asset sales. Our focus is to continue to grow all three business segments while retaining the financial discipline our shareholders have grown to expect."

Unit's 2018 capital expenditures budget is $352 million, which represents a 27% increase over 2017, excluding acquisitions. The capital expenditures plan by segment is: $272 million for the oil and natural gas segment, $47 million for the contract drilling segment, and $32 million for the midstream segment, representing an increase of 26%, 30% and 44%, respectively, over 2017. The budget for the year includes no costs for potential acquisitions and is based on prices, after applying differentials and hedges, averaging $53.19 per barrel for oil, $22.18 per barrel for NGLs, and $2.16 per Mcf for natural gas. As always, Unit's capital budget is subject to periodic review based on prevailing conditions.

In 2017, year over year production in Unit's oil and natural gas segment declined 7%; however, in each of the last three quarters of 2017 production grew sequentially. It is anticipated that 2018 production should grow to 17.1 to 17.4 MMBoe, or 7% to 9% year over year from 2017.

FINANCIAL INFORMATION

Unit ended the quarter with long-term debt of $820.3 million, consisting of $642.3 million of senior subordinated notes (net of unamortized discount and debt issuance costs) and $178.0 million of borrowings under the company's credit agreement. During October, Unit's borrowing base was re-determined with no resulting change. Under the credit agreement, the amount Unit can borrow is the lesser of the amount it elects as the commitment amount ($475 million) or the value of its borrowing base as determined by the lenders ($475 million).

WEBCAST

Unit uses its website to disclose material nonpublic information and for complying with its disclosure obligations under Regulation FD. Those disclosures will be included on its website in the 'Investor Information' sections. Accordingly, investors should monitor that portion of the website, besides following the press releases, SEC filings, and public conference calls and webcasts.

Unit will webcast its fourth quarter earnings conference call live over the Internet on February 22, 2018 at 10:00 a.m. Central Time (11:00 a.m. Eastern). To listen to the live call, please go to http://www.unitcorp.com/investor/calendar.htm at least fifteen minutes before the start of the call to download and install any necessary audio software. For those who are not available to listen to the live webcast, a replay will be available shortly after the call and will remain on the site for 90 days.

Unit Corporation is a Tulsa-based, publicly held energy company engaged through its subsidiaries in oil and gas exploration, production, contract drilling, and gas gathering and processing. Unit's Common Stock is on the New York Stock Exchange under the symbol UNT. For more information about Unit Corporation, visit its website at http://www.unitcorp.com.

FORWARD-LOOKING STATEMENT

This news release contains forward-looking statements within the meaning of the private Securities Litigation Reform Act. All statements, other than statements of historical facts, included in this release that address activities, events, or developments that the company expects, believes, or anticipates will or may occur are forward-looking statements. Several risks and uncertainties could cause actual results to differ materially from these statements, including changes in commodity prices, the productive capabilities of the company's wells, future demand for oil and natural gas, future drilling rig utilization and dayrates, projected rate of the company's oil and natural gas production, the amount available to the company for borrowings, its anticipated borrowing needs under its credit agreement, the number of wells to be drilled by the company's oil and natural gas segment, the potential productive capability of its prospective plays including the STACK play, the number of additional shares (if any) it may sell under its "at the market" offering, and other factors described occasionally in the company’s publicly available SEC reports. The company assumes no obligation to update publicly such forward-looking statements, whether because of new information, future events, or otherwise.

Unit Corporation
Selected Financial Highlights
(In thousands except per share amounts)

	Three Months Ended December 31, 2017	Three Months Ended December 31, 2016	Twelve Months Ended December 31, 2017	Twelve Months Ended December 31, 2016
Statement of Operations:				
Revenues:				
Oil and natural gas	$ 101,503	$ 87,903	$ 357,744	$ 294,221
Contract drilling	46,661	33,300	174,720	122,086
Gas gathering and processing	56,683	53,077	207,176	185,870
Total revenues	204,847	174,280	739,640	602,177
Expenses:				
Operating costs:				
Oil and natural gas	34,916	27,493	130,789	120,184
Contract drilling	31,387	21,665	122,600	88,154
Gas gathering and processing	43,621	38,424	155,483	137,609
Total operating costs	109,924	87,582	408,872	345,947
Depreciation, depletion, and amortization	57,712	48,925	209,257	208,353
Impairments	—	—	—	161,563
General and administrative	11,185	8,517	38,087	33,337
(Gain) loss on disposition of assets	826	(1,717)	(327)	(2,540)
Total expenses	179,647	143,307	655,889	746,660
Income (loss) from operations	25,200	30,973	83,751	(144,483)
Other income (expense):				
Interest, net	(9,527)	(9,604)	(38,334)	(39,829)
Gain (loss) on derivatives not designated as hedges	(6,287)	(18,039)	14,732	(22,813)
Other	7	318	21	307
Total other income (expense)	(15,807)	(27,325)	(23,581)	(62,335)
Income (loss) before income taxes	9,393	3,648	60,170	(206,818)
Income tax expense (benefit):				
Current	5	15	5	15
Deferred	(79,767)	1,950	(57,683)	(71,209)
Total income taxes	(79,762)	1,965	(57,678)	(71,194)
Net income (loss)	$ 89,155	$ 1,683	$ 117,848	$ (135,624)
Net income (loss) per common share:				
Basic	$ 1.74	$ 0.03	$ 2.31	$ (2.71)
Diluted	$ 1.71	$ 0.03	$ 2.28	$ (2.71)
Weighted average shares outstanding:				
Basic	51,394	50,081	51,113	50,029
Diluted	52,201	50,949	51,748	50,029

	December 31, 2017	December 31, 2016
Balance Sheet Data:		
Current assets	$ 119,672	$ 121,196
Total assets	$ 2,581,452	$ 2,479,303
Current liabilities	$ 181,936	$ 164,915
Long-term debt	$ 820,276	$ 800,917
Other long-term liabilities	$ 100,203	$ 103,479
Deferred income taxes	$ 133,477	$ 215,922
Shareholders' equity	$ 1,345,560	$ 1,194,070

	Twelve Months Ended December 31, 2017	2016
Statement of Cash Flows Data:		
Cash flow from operations before changes in operating assets and liabilities	$ 276,811	$ 205,888
Net change in operating assets and liabilities	2,777	34,242
Net cash provided by operating activities	$ 279,588	$ 240,130
Net cash used in investing activities	$ (306,998)	$ (110,971)
Net cash provided by (used in) financing activities	$ 27,218	$ (129,101)

Non-GAAP Financial Measures

Unit Corporation reports its financial results under generally accepted accounting principles ("GAAP"). The company believes certain Non-GAAP performance measures provide users of its financial information and its management additional meaningful information to evaluate the performance of the company.

This press release includes net income (loss) and earnings (loss) per share excluding impairment adjustments, the effect of the cash settled commodity derivatives and the effect of the tax benefit from the Tax Act, its exploration and production segment's reconciliation of PV-10 to Standard Measure, its reconciliation of segment operating profit, its drilling segment's average daily operating margin before elimination of intercompany drilling rig profit and bad debt expense, its cash flow from operations before changes in operating assets and liabilities, and its reconciliation of net income (loss) to adjusted EBITDA.

Below is a reconciliation of GAAP financial measures to Non-GAAP financial measures for the three and twelve months ended December 31, 2017 and 2016. Non-GAAP financial measures should not be considered by themselves or a substitute for results reported under GAAP. This Non-GAAP information should be considered by the reader besides, but not instead of, the financial statements prepared under GAAP. The Non-GAAP financial information presented may be determined or calculated differently by other companies and may not be comparable to similarly titled measures.

Unit Corporation
Reconciliation of Adjusted Net Income (Loss) and Adjusted Diluted Earnings (Loss) per Share

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2017	2016	2017	2016
	(In thousands except earnings per share)			
Adjusted net income:				
Net income (loss)	$ 89,155	$ 1,683	$ 117,848	$ (135,624)
Impairment adjustment (net of income tax)	—	—	—	100,573
(Gain) loss on derivatives (net of income tax)	2,930	11,845	(8,949)	14,960
Settlements during the period of matured derivative contracts (net of income tax)	517	(1,322)	105	6,333
Tax Act income tax benefit	(81,307)	—	(81,307)	—
Adjusted net income (loss)	$ 11,295	$ 12,206	$ 27,697	$ (13,758)
Adjusted diluted earnings per share:				
Diluted earnings (loss) per share	$ 1.71	$ 0.03	$ 2.28	$ (2.71)
Diluted earnings per share from the impairments	—	—	—	2.01
Diluted earnings per share from the (gain) loss on derivatives	0.06	0.23	(0.17)	0.30
Diluted earnings (loss) per share from the settlements of matured derivative contracts	0.01	(0.03)	—	0.12
Diluted earnings (loss) per share from the Tax Act income tax benefit	(1.56)	—	(1.57)	—
Adjusted diluted earnings (loss) per share	$ 0.22	$ 0.23	$ 0.54	$ (0.28)

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The company has included the net income and diluted earnings per share including only the cash settled commodity derivatives because:

- It uses the adjusted net income to evaluate the operational performance of the company.
- The adjusted net income is more comparable to earnings estimates provided by securities analysts.

Unaudited Reconciliation of PV-10 to Standard Measure
December 31, 2017

PV-10 is the estimated future net cash flows from proved reserves discounted at an annual rate of 10 percent before giving effect to income taxes. Standardized Measure is the after-tax estimated future cash flows from proved reserves discounted at an annual rate of 10 percent, determined under GAAP. The company uses PV-10 as one measure of the value of its proved reserves and to compare relative values of proved reserves among exploration and production companies without regard to income taxes. The company believes that securities analysts and rating agencies use PV-10 in similar ways. The company's management believes PV-10 is a useful measure for comparison of proved reserve values among companies because, unlike Standardized Measure, it excludes future income taxes that often depend principally on the characteristics of the owner of the reserves rather than on the nature, location and quality of the reserves themselves. Below is a reconciliation of PV-10 to Standardized Measure:

	2017
	(In millions)
PV-10 at December 31, 2017	$ 897.5
Discounted effect of income taxes	(90.3)
Standardized Measure at December 31, 2017	$ 807.2

Unit Corporation
Reconciliation of Segment Operating Profit

	Three Months Ended			Twelve Months Ended	
	September 30,	December 31,		December 31,	
	2017	2017	2016	2017	2016
			(In thousands)		
Oil and natural gas	$ 51,559	$ 66,587	$ 60,410	$ 226,955	$ 174,037
Contract drilling	16,872	15,274	11,635	52,120	33,932
Gas gathering and processing	13,283	13,062	14,653	51,693	48,261
Total operating profit	81,714	94,923	86,698	330,768	256,230
Depreciation, depletion and amortization	(54,533)	(57,712)	(48,925)	(209,257)	(208,353)
Impairments	—	—	—	—	(161,563)
Total operating income (loss)	27,181	37,211	37,773	121,511	(113,686)
General and administrative	(9,235)	(11,185)	(8,517)	(38,087)	(33,337)
Gain (loss) on disposition of assets	81	(826)	1,717	327	2,540
Interest, net	(9,944)	(9,527)	(9,604)	(38,334)	(39,829)
Gain (loss) on derivatives	(2,614)	(6,287)	(18,039)	14,732	(22,813)
Other	5	7	318	21	307
Income (loss) before income taxes	$ 5,474	$ 9,393	$ 3,648	$ 60,170	$ (206,818)

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The company has included segment operating profit because:

- It considers segment operating profit to be an important supplemental measure of operating performance for presenting trends in its core businesses.
- Segment operating profit is useful to investors because it provides a means to evaluate the operating performance of the segments and company on an ongoing basis using criteria used by management.

Unit Corporation
Reconciliation of Average Daily Operating Margin Before Elimination of Intercompany Rig Profit and Bad Debt Expense

	Three Months Ended			Twelve Months Ended	
	September 30,	December 31,		December 31,	
	2017	2017	2016	2017	2016
	(In thousands except for operating days and operating margins)				
Contract drilling revenue	$ 51,619	$ 46,661	$ 33,300	$ 174,720	$ 122,086
Contract drilling operating cost	34,747	31,387	21,665	122,600	88,154
Operating profit from contract drilling	16,872	15,274	11,635	52,120	33,932
Add:					
Elimination of intercompany rig profit and bad debt expense	602	642	—	1,620	235
Operating profit from contract drilling before elimination of intercompany rig profit and bad debt expense	17,474	15,916	11,635	53,740	34,167
Contract drilling operating days	3,180	2,868	1,796	10,964	6,374
Average daily operating margin before elimination of intercompany rig profit and bad debt expense	$ 5,495	$ 5,550	$ 6,478	$ 4,901	$ 5,360

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The company has included the average daily operating margin before elimination of intercompany rig profit and bad debt expense because:

- Its management uses the measurement to evaluate the cash flow performance of its contract drilling segment and to evaluate the performance of contract drilling management.
- It is used by investors and financial analysts to evaluate the performance of the company.

Unit Corporation
Reconciliation of Cash Flow from Operations Before Changes in Operating Assets and Liabilities

	Twelve Months Ended December 31,	
	2017	2016
	(In thousands)	
Net cash provided by operating activities	$ 279,588	$ 240,130
Net change in operating assets and liabilities	(2,777)	(34,242)
Cash flow from operations before changes in operating assets and liabilities	$ 276,811	$ 205,888

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The company has included the cash flow from operations before changes in operating assets and liabilities because:

- It is an accepted financial indicator used by its management and companies in the industry to measure the company’s ability to generate cash used to internally fund its business activities.
- It is used by investors and financial analysts to evaluate the performance of the company.

Unit Corporation
Reconciliation of Adjusted EBITDA

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2017	2016	2017	2016
	(In thousands except earnings per share)			
Net income (loss)	$ 89,155	$ 1,683	$ 117,848	$ (135,624)
Income taxes	(79,762)	1,965	(57,678)	(71,194)
Depreciation, depletion and amortization	57,712	48,925	209,257	208,353
Amortization of debt issuance costs and debt discounts	543	536	2,159	2,122
Impairments	—	—	—	161,563
Interest expense	9,527	9,604	38,334	39,829
(Gain) loss on derivatives	6,287	18,039	(14,732)	22,813
Settlements during the period of matured derivative contracts	902	(2,077)	173	9,658
Stock compensation plans	5,269	3,148	17,747	13,812
Other non-cash items	774	632	2,886	2,779
(Gain) loss on disposition of assets	826	(1,717)	(327)	(2,540)
Adjusted EBITDA	$ 91,233	$ 80,738	$ 315,667	$ 251,571
Diluted earnings (loss) per share	$ 1.71	$ 0.03	$ 2.28	$ (2.71)
Diluted earnings per share from income taxes	(1.53)	0.04	(1.11)	(1.42)
Diluted earnings per share from depreciation, depletion and amortization	1.11	0.96	4.04	4.12
Diluted earnings per share from amortization of debt issuance costs and debt discounts	0.01	0.01	0.04	0.04
Diluted earnings per share from impairments	—	—	—	3.24
Diluted earnings per share from interest expense	0.18	0.19	0.74	0.79
Diluted earnings per share from the (gain) loss on derivatives	0.12	0.35	(0.28)	0.45
Diluted earnings per share from the settlements during the period of matured derivative contracts	0.02	(0.04)	—	0.20
Diluted earnings per share from stock compensation plans	0.10	0.06	0.34	0.27
Diluted earnings per share from other non-cash items	0.01	0.01	0.06	0.05
Diluted earnings per share (gain) loss on disposition of assets	0.02	(0.03)	(0.01)	(0.05)
Adjusted EBITDA per diluted share	$ 1.75	$ 1.58	$ 6.10	$ 4.98

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The company has included adjusted EBITDA, which excludes gain or loss on disposition of assets and includes only the cash settled commodity derivatives because:

- It uses adjusted EBITDA to evaluate the operational performance of the company.
- Adjusted EBITDA is more comparable to estimates provided by securities analysts.