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 21, 2019

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 21, 2019, the Company issued a press release announcing its financial results for the three and twelve month periods ending December 31, 2018. 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 21, 2019

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 21, 2019

By: /s/ Les Austin
Les Austin
Senior Vice President and Chief Financial Officer

EXHIBIT INDEX

Exhibit No.	**Description**
99.1	Press release dated February 21, 2019

News

UNIT CORPORATION

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www.unitcorp.com

For Immediate Release…
February 21, 2019

UNIT CORPORATION REPORTS 2018 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 2018. Fourth quarter and 2018 operational highlights include:

- Oil and natural gas segment production increased 7% year-over-year from 2017.
- Total year-end 2018 proved oil and natural gas reserves increased 7% over 2017, and 158% of 2018 production was replaced with new reserves.
- In December, Unit acquired approximately 8,700 net acres in the Penn sands play in western Oklahoma adding additional oil prospects similar to Unit's existing Southern Oklahoma Hoxbar Oil Trend (SOHOT) play. The final adjusted price of the acquisition totaled approximately $29.6 million and included net proved reserves of 2.6 million barrels of oil equivalent (MMBoe). The acquisition provides Unit with 20 to 30 horizontal drilling locations and 82% of the acreage is held by production.
- Contract drilling segment placed its 11th BOSS rig into service during the second quarter. Its 12th BOSS rig was placed into service during January 2019. Further, its 13th BOSS rig was recently placed into service under a long-term contract.
- During the quarter, the mid-stream segment completed the connection of the Miller Pad to its Pittsburgh Mills gathering system. The wells from the new pad began being placed online in late January 2019.
- The mid-stream segment's natural gas gathering, processing and liquids sold volumes increased 2%, 15% and 24% year-over-year, respectively.
- Unit amended its bank credit agreement during the quarter, in part extending its maturity until October 2023.

FOURTH QUARTER AND YEAR-END 2018 FINANCIAL RESULTS

Net loss attributable to Unit for the quarter was $77.8 million, or $1.49 loss per diluted share, compared to net income attributable to Unit of $89.2 million, or $1.71 per diluted share, for the fourth quarter of 2017. (For the fourth quarter of 2017, Unit recorded an $81.3 million net tax benefit related to tax legislation enacted during the quarter.) For the fourth quarter of 2018, Unit recorded a pre-tax non-cash write-down of $147.9 million associated with the removal of 41 drilling rigs from its drilling fleet along with some other equipment. The drilling rigs removed from service included our remaining 29 mechanical drilling rigs and 12 SCR drilling rigs. The company strategically decided to focus on its new BOSS drilling rigs and specific SCR drilling rigs (good candidates for modification) and sell the other drilling rigs it now chooses not to market. Adjusted net income attributable to Unit for the quarter (which excludes the effect of non-cash commodity derivatives and the write-down) was $13.8 million, or $0.27 per diluted share compared to $0.22 per diluted share for the same quarter for 2017, a 22% increase in adjusted net income (see Non-GAAP financial measures below). Total revenues for the quarter were $214.8 million (49% oil and natural gas, 25% contract drilling, and 26% mid-stream), compared to $204.8 million (49% oil and natural gas, 23% contract drilling, and 28% mid-stream) for the fourth quarter of 2017. Adjusted EBITDA attributable to Unit was $88.2 million, or $1.69 per diluted share (see Non-GAAP financial measures below).

For 2018, net loss attributable to Unit was $45.3 million, or $0.87 loss per diluted share, compared to net income of $117.8 million, or $2.28 per diluted share, for 2017 (which included the net tax benefit discussed above). For the same period, adjusted net income attributable to Unit (which excludes the effect of non-cash commodity derivatives and the write-down) was $51.9 million, or $1.00 per diluted share, compared to $0.54 per diluted share for 2017, an 87% increase in adjusted net income (see Non-GAAP financial measures below). Total revenues for the year were $843.3 million (50% oil and natural gas, 23% contract drilling, and 27% mid-stream), compared to $739.6 million (48% oil and natural gas, 24% contract drilling, and 28% mid-stream) for 2017. Adjusted EBITDA attributable to Unit for 2018 was $349.7 million, or $6.73 per diluted share (see Non-GAAP financial measures below).

MANAGEMENT COMMENTS

Larry Pinkston, Unit's Chief Executive Officer and President, said: "During the fourth quarter, as part of our periodic evaluation process, we removed 41 drilling rigs from our fleet as well as some other equipment. Those rigs included our 29 remaining mechanical drilling rigs and 12 of our SCR drilling rigs that were not considered to be economic to upgrade to meet market demands. Our remaining rig fleet includes 13 BOSS AC drilling rigs as well as upgraded SCR rigs that are well suited for current operator requirements. Additionally, we have other SCR rigs that are available to return to service as market conditions and demand improve or are good candidates for upgrade to meet future customer demands and requirements. Our drilling rig fleet now totals 57 rigs."

"For our oil and natural gas segment, we are focusing on increasing the proportion of oil in our production mix. As part of this effort, we are building a position in western Oklahoma to add drilling inventory in prospective areas we believe have a greater concentration of oil. We continue to look for bolt-on opportunities near our existing core areas."

OIL AND NATURAL GAS SEGMENT INFORMATION

For the quarter, total equivalent production was 4.3 MMBoe, a 1% decrease from the third quarter of 2018. Oil and natural gas liquids (NGLs) production represented 46% of total equivalent production, of which, oil production increased 9% over the third quarter of 2018. Oil production was 8,187 barrels per day. NGLs production was 13,290 barrels per day. Natural gas production was 152.8 million cubic feet (MMcf) per day. Overall, total production for 2018 was 17.1 MMBoe, a 7% increase over 2017.

Unit's average realized per barrel equivalent price for the quarter was $23.99, a 1% decrease from the third quarter of 2018. Unit's average oil price was $54.01 per barrel, a decrease of 6% from the third quarter of 2018. Unit's average NGLs price was $19.61 per barrel, a decrease of 24% from the third quarter of 2018. Unit's average natural gas price was $2.77 per Mcf, an increase of 22% over the third quarter of 2018. All prices in this paragraph include the effects of derivative contracts.

Late in the third quarter 2018, Unit drilled the Schrock 22/15 #1HX in the Penn sands prospect area in western Oklahoma, the first Red Fork extended lateral well drilled in Oklahoma. The Schrock IP30 was over 2,000 barrels of oil equivalent (Boe) per day with an approximate 80% oil cut. In addition, Unit brought on the Frymire 1-18H, a second Red Fork lateral well in late October, which had an IP30 of 850 Boe per day that was primarily high BTU natural gas with some oil. The well cost for the Red Fork wells was approximately $6 million for a one-mile lateral and $7.5 million for a two-mile lateral. Subsequent to these well results, Unit acquired offsetting oil and natural gas assets in December for $29.6 million. The acquired properties added approximately 8,700 net acres largely held by production to the Penn sands area, including 44 wells and approximately 2.6 MMBoe of proved reserves. The acquisition provides Unit approximately 20 to 30 horizontal Red Fork drilling locations, which are anticipated to have a significant percentage of oil in the total production stream.

In the SOHOT play, in western Oklahoma, primarily in Grady County, Unit continues to drill horizontal wells in the oily Marchand sand. Unit is having success adding small parcels of acreage at a reasonable cost which should permit the company to add a second rig to its drilling program in the second quarter.

In the Texas Panhandle Granite Wash play, Unit continued its one rig drilling program. The results from its first two Granite Wash "G" extended lateral wells in the field have been good with initial rates from each well exceeding 10 MMcfe per day. Unit is continuing with its Granite Wash drilling program through the first quarter of 2019 before moving the rig to its western Oklahoma assets that are likely to have a higher oil cut. Unit's land position in the Texas Panhandle area is largely held by production allowing it to drill when pricing is most optimal.

In the Wilcox play, Unit continued its development drilling and re-completion program during the fourth quarter. Additionally, Unit drilled a successful delineation well in its Shoal Creek prospect that has continued to increase in production since coming online in October and is currently producing approximately 8.5 MMcfe per day of high BTU gas and oil. Unit will continue delineating this and other prospects in 2019, one of which will be the Wolf Pasture #1, the first delineation well in its Cherry Creek prospect. In addition, Unit plans to complete approximately 10 behind pipe gas and liquids zones during 2019.

Pinkston said: "Our oil and natural gas segment continues to focus on expanding the favorable results we have obtained western Oklahoma by increasing our footprint in that area. Our acquisition in the Penn sands area follows the strong results from our two Red Fork wells described in the operations update. We remain focused on adding to this position."

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, 2018	Dec 31, 2017	Change		Dec 31, 2018	Sept 30, 2018	Change		Dec 31, 2018	Dec 31, 2017	Change
Oil and NGLs Production, MBbl	1,976	1,986	(1)%		1,976	1,970	—%		7,799	7,453	5%
Natural Gas Production, Bcf	14.1	13.9	1%		14.1	14.3	(2)%		55.6	51.3	9%
Production, MBoe	4,318	4,310	—%		4,318	4,359	(1)%		17,070	15,996	7%
Production, MBoe/day	46.9	46.8	—%		46.9	47.4	(1)%		46.8	43.8	7%
Avg. Realized Natural Gas Price, Mcf (1)	$ 2.77	$ 2.38	16%		$ 2.77	$ 2.27	22%		$ 2.46	$ 2.46	—%
Avg. Realized NGL Price, Bbl (1)	$ 19.61	$ 21.88	(10)%		$ 19.61	$ 25.66	(24)%		$ 22.18	$ 18.35	21%
Avg. Realized Oil Price, Bbl (1)	$ 54.01	$ 54.45	(1)%		$ 54.01	$ 57.72	(6)%		$ 55.78	$ 49.44	13%
Realized Price / Boe (1)	$ 23.99	$ 23.25	3%		$ 23.99	$ 24.15	(1)%		$ 23.80	$ 21.72	10%
Operating Profit Before Depreciation, Depletion, Amortization & Impairment (MM) (2)	$ 74.9	$ 66.6	12%		$ 74.9	$ 79.5	(6)%		$ 291.4	$ 227.0	28%

1. Realized price includes oil, NGLs, natural gas, and associated derivatives.
2. Unit calculates operating profit before depreciation by taking operating revenues for this segment less operating expenses excluding depreciation, depletion, amortization, and impairment. (See Non-GAAP financial measures below.)

YEAR-END 2018 ESTIMATED PROVED RESERVES

The discount rate (PV-10) value of Unit's estimated year-end 2018 proved reserves increased 23% over 2017 to $1.1 billion. Estimated year-end 2018 proved oil and natural gas reserves were 159.7 MMBoe, or 958.1 billion cubic feet of natural gas equivalents (Bcfe), as compared with 149.8 MMBoe, or 898.6 Bcfe, at year-end 2017, a 7% increase. Estimated reserves were 14% oil, 30% NGLs, and 56% natural gas.

The following details the changes to Unit's proved oil, NGLs, and natural gas reserves during 2018:

	Oil (MMbls)	NGLs (MMbls)	Natural Gas (Bcf)	Proved Reserves (MMBoe)
Proved Reserves, at December 31, 2017	19.5	45.5	508.7	149.8
Revisions of previous estimates	0.2	(1.4)	(17.9)	(4.1)
Extensions, discoveries, and other additions	5.2	7.9	99.6	29.7
Purchases of minerals in place	0.7	0.9	6.9	2.7
Production	(2.9)	(4.9)	(55.6)	(17.1)
Sales	(0.1)	(0.2)	(5.7)	(1.3)
Proved Reserves, at December 31, 2018	22.6	47.8	536.0	159.7

Estimated 2018 year-end proved reserves included proved developed reserves of 111.6 MMBoe, or 669.5 Bcfe, (14% oil, 30% NGLs, and 56% natural gas) and proved undeveloped reserves of 48.1 MMBoe, or 288.6 Bcfe, (15% oil, 30% NGLs, and 55% natural gas). Overall, 70% of the estimated proved reserves are proved developed.

The present value of the estimated future net cash flows from 2018 estimated proved reserves (before income taxes and using a PV-10), is approximately $1.1 billion. The present value was determined using the required SEC's pricing methodology. The benchmark price used for all future reserves was $65.56 per barrel of oil, $37.68 per barrel of NGLs, and $3.10 per Mcf of natural gas (then adjusted for price differentials). Ryder Scott Company, L.P. independently audited Unit's 2018 year-end proved reserves. Their audit covered properties accounting for 82% 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 2018, we achieved our goal by replacing 158% of production with new reserves and maintained a capital expenditure program in line with our cash flow and proceeds from divestitures."

CONTRACT DRILLING SEGMENT INFORMATION

Unit's average number of working drilling rigs during the quarter was 33.1, a decrease of 3% from the third quarter of 2018. Per day drilling rig rates averaged $18,047, a 3% increase over the third quarter of 2018. Average per day operating margin for the quarter was $5,859 (before elimination of intercompany drilling rig profit and bad debt expense of $0.6 million). This compares to third quarter 2018 average operating margin of $6,291 (before elimination of intercompany drilling rig profit of $1.2 million), a decrease of 7%, or $432.

Pinkston said: "During the quarter, drilling rig demand declined as operators made adjustments because of the decrease in commodity prices. During January, we completed and placed into service our 12th BOSS rig. And this month our 13th BOSS rig was placed into service under a long-term contract. Currently, we have 32 rigs operating. We had 24 long-term contracts (contracts with original terms ranging from six months to three years in length) as of the end of the quarter. Included in these 24 term contracts are the two new BOSS rigs that have been placed into service, noted above, and two term contracts that rolled over in the first quarter of 2019 to two year terms. Of the remaining 20 long-term contracts, seven are up for renewal in the first quarter of 2019, seven in the second quarter, one in the third quarter, two in the fourth quarter, and three in 2020 and thereafter."

This table illustrates certain comparative results for the periods indicated:

	Three Months Ended			**Three Months Ended**			**Twelve Months Ended**		
	Dec 31, 2018	**Dec 31, 2017**	**Change**	**Dec 31, 2018**	**Sept 30, 2018**	**Change**	**Dec 31, 2018**	**Dec 31, 2017**	**Change**
Rigs Utilized	33.1	31.2	6%	33.1	34.2	(3)%	32.8	30.0	9%
Operating Profit Before Depreciation (MM) (1)	$ 17.2	$ 15.3	12%	$ 17.2	$ 18.6	(8)%	$ 65.1	$ 52.1	25%

1. Unit calculates operating profit before depreciation by taking operating revenues for this segment less operating expenses excluding depreciation and impairment. (See Non-GAAP financial measures below.)

MID-STREAM SEGMENT INFORMATION

For the quarter, gas gathering and liquids sold volumes per day decreased 5% and 1%, respectively, while gas processing volumes per day remained relatively unchanged, as compared to the third quarter of 2018. Operating profit (as defined in the footnote below) for the quarter was $12.5 million, a decrease of 15% from the third quarter of 2018.

This table illustrates certain comparative results for the periods indicated:

	Three Months Ended			**Three Months Ended**			**Twelve Months Ended**		
	Dec 31, 2018	**Dec 31, 2017**	**Change**	**Dec 31, 2018**	**Sept 30, 2018**	**Change**	**Dec 31, 2018**	**Dec 31, 2017**	**Change**
Gas Gathering, Mcf/day	394,203	383,319	3%	394,203	415,862	(5)%	393,613	385,209	2%
Gas Processing, Mcf/day	160,786	148,422	8%	160,786	160,294	—%	158,189	137,625	15%
Liquids Sold, Gallons/day	697,161	581,874	20%	697,161	700,523	(1)%	663,367	534,140	24%
Operating Profit Before Depreciation and Amortization (MM) (1)	$ 12.4	$ 13.1	(5)%	$ 12.4	$ 14.7	(16)%	$ 55.9	$ 51.7	8%

1. Unit calculates operating profit before depreciation by taking operating revenues for this segment less operating expenses excluding depreciation, amortization, and impairment. (See Non-GAAP financial measures below.)

Pinkston said: "Our mid-stream segment completed the connection of the J. R. Miller pad to its Pittsburgh Mills gathering system during the fourth quarter. The operator of that pad began bringing two of the seven new wells on line in January. Superior continues to make progress on the construction of its new Reeding gas processing plant, which will be integrated into its Cashion gathering system. The new gas processing plant is anticipated to commence operation by the end of the first quarter."

2019 CAPITAL BUDGET AND PRODUCTION GUIDANCE

Unit's 2019 capital budget is anticipated to range from $336 million to $422 million, a decrease of 27% to 8% from 2018, excluding acquisitions. The decrease is in response to the current commodity price environment and keeps the budget in-line with anticipated cash flow plus proceeds from any non-core asset sales. The capital budget is allocated, as follows, among the three business segments: $271 million to $315 million for the oil and natural gas segment; $30 million to $65 million for the contract drilling segment; and $35 million to $42 million for the mid-stream segment. The budget does not include amounts for any possible acquisitions and is based on realized prices for the year averaging $55.04 per barrel of oil, $24.73 per barrel of natural gas liquids, and $3.00 per Mcf of natural gas (all prices are before differentials and hedges are applied).

Unit's oil and natural gas segment's 2019 production is anticipated to be 17.4 to 17.9 MMBoe (an increase of 2% to 5%, year-over-year) based on the capital budget range.

Pinkston said: "We have considerably reduced our 2019 capital expenditure plans from 2018 levels. Historically, we have focused on keeping our capital expenditure budget in line with anticipated cash flow, adjusting our spending mid-year if conditions warranted a change. We begin 2019 with the same objective of maintaining our capital spending in line with anticipated cash flow."

FINANCIAL INFORMATION

Unit ended the quarter with long-term debt of $644.5 million, consisting solely of senior subordinated notes (net of unamortized discount and debt issuance costs) and no borrowings under the Unit or Superior credit agreements. In October, Unit signed the Fifth Amendment to its credit agreement providing in part for the extension of the maturity to October 18, 2023. The Unit credit agreement is subject to an elected commitment and borrowing base of $425 million. Besides extending the term, the amendment increased the company's flexibility around issuing senior notes and lowered the pricing on certain borrowings and fees.

WEBCAST

Unit uses its website to disclose material nonpublic information and for complying with its disclosure obligations under Regulation FD. The website includes those disclosures in the 'Investor Information' sections. So, 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 21, 2019, 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, 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,		Twelve Months Ended December 31,	
	2018	**2017**	**2018**	**2017**
Statement of Operations:				
Revenues:				
Oil and natural gas	$ 106,019	$ 101,503	$ 423,059	$ 357,744
Contract drilling	52,965	46,661	196,492	174,720
Gas gathering and processing	55,804	56,683	223,730	207,176
Total revenues	214,788	204,847	843,281	739,640
Expenses:				
Operating costs:				
Oil and natural gas	31,156	34,916	131,675	130,789
Contract drilling	35,792	31,387	131,385	122,600
Gas gathering and processing	43,395	43,621	167,836	155,483
Total operating costs	110,343	109,924	430,896	408,872
Depreciation, depletion, and amortization	64,629	57,712	243,605	209,257
Impairments	147,884	—	147,884	—
General and administrative	9,955	11,185	38,707	38,087
(Gain) loss on disposition of assets	(129)	826	(704)	(327)
Total expenses	332,682	179,647	860,388	655,889
Income (loss) from operations	(117,894)	25,200	(17,107)	83,751
Other income (expense):				
Interest, net	(7,816)	(9,527)	(33,494)	(38,334)
Gain (loss) on derivatives not designated as hedges	22,424	(6,287)	(3,184)	14,732
Other	5	7	22	21
Total other income (expense)	14,613	(15,807)	(36,656)	(23,581)
Income (loss) before income taxes	(103,281)	9,393	(53,763)	60,170
Income tax expense (benefit):				
Current	(3,131)	5	(3,131)	5
Deferred	(23,245)	(79,767)	(10,865)	(57,683)
Total income taxes	(26,376)	(79,762)	(13,996)	(57,678)
Net income (loss)	(76,905)	89,155	(39,767)	117,848
Net income attributable to non-controlling interest	935	—	5,521	—
Net income (loss) attributable to Unit Corporation	$ (77,840)	$ 89,155	$ (45,288)	$ 117,848
Net income (loss) attributable to Unit Corporation per common share:				
Basic	$ (1.49)	$ 1.71	$ (0.87)	$ 2.31
Diluted	$ (1.49)	$ 1.71	$ (0.87)	$ 2.28
Weighted average shares outstanding:				
Basic	52,070	51,394	51,981	51,113
Diluted	52,070	52,201	51,981	51,748

Unit Corporation
Selected Financial Highlights - continued
(In thousands)

	Twelve Months Ended December 31,	
	2018	**2017**
Statement of Cash Flows Data:		
Cash flow from operations before changes in operating assets and liabilities	$ 345,582	$ 276,811
Net change in operating assets and liabilities	2,177	(10,855)
Net cash provided by operating activities	$ 347,759	$ 265,956
Net cash used in investing activities	$ (450,342)	$ (293,366)
Net cash provided by (used in) financing activities	$ 108,334	$ 27,218

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, 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, 2018 and 2017. 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 beside, 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,	
	2018	2017	2018	2017
	(In thousands except earnings per share)			
Adjusted net income attributable to Unit Corporation:				
Net income (loss) attributable to Unit Corporation	$ (77,840)	$ 89,155	$ (45,288)	$ 117,848
Impairment adjustment (net of income tax)	111,652	—	111,652	—
(Gain) loss on derivatives (net of income tax)	(16,198)	2,930	2,356	(8,949)
Settlements during the period of matured derivative contracts (net of income tax)	(3,796)	517	(16,867)	105
Tax Act income tax benefit	—	(81,307)	—	(81,307)
Adjusted net income (loss)	$ 13,818	$ 11,295	$ 51,853	$ 27,697
Adjusted diluted earnings per share attributable to Unit Corporation:				
Diluted earnings (loss) per share	$ (1.49)	$ 1.71	$ (0.87)	$ 2.28
Diluted earnings per share from the impairments	2.14	—	2.14	—
Diluted earnings per share from the (gain) loss on derivatives	(0.31)	0.06	0.05	(0.17)
Diluted earnings (loss) per share from the settlements of matured derivative contracts	(0.07)	0.01	(0.32)	—
Diluted earnings (loss) per share from the Tax Act income tax benefit	—	(1.56)	—	(1.57)
Adjusted diluted earnings (loss) per share attributable to Unit Corporation	$ 0.27	$ 0.22	$ 1.00	$ 0.54
Weighted Shares (Denominator)	52,070	52,201	51,981	51,748

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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, 2018

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:

	2018
	(In millions)
PV-10 at December 31, 2018	$ 1,105.7
Discounted effect of income taxes	(122.0)
Standardized Measure at December 31, 2018	$ 983.7

Unit Corporation
Reconciliation of Segment Operating Profit

	Three Months Ended			Twelve Months Ended	
	September 30,	December 31,		December 31,	
	2018	2018	2017	2018	2017
	(In thousands)				
Oil and natural gas	$ 79,484	$ 74,863	$ 66,587	$ 291,384	$ 226,955
Contract drilling	18,580	17,173	15,274	65,107	52,120
Gas gathering and processing	14,689	12,409	13,062	55,894	51,693
Total operating profit	112,753	104,445	94,923	412,385	330,768
Depreciation, depletion and amortization	(63,537)	(64,629)	(57,712)	(243,605)	(209,257)
Impairments	—	(147,884)	—	(147,884)	—
Total operating income (loss)	49,216	(108,068)	37,211	20,896	121,511
General and administrative	(9,278)	(9,955)	(11,185)	(38,707)	(38,087)
Gain (loss) on disposition of assets	253	129	(826)	704	327
Interest, net	(7,945)	(7,816)	(9,527)	(33,494)	(38,334)
Gain (loss) on derivatives	(4,385)	22,424	(6,287)	(3,184)	14,732
Other	6	5	7	22	21
Income (loss) before income taxes	$ 27,867	$ (103,281)	$ 9,393	$ (53,763)	$ 60,170

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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 ongoing operating performance of the segments and company 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,	
	2018	2018	2017	2018	2017
	(In thousands except for operating days and operating margins)				
Contract drilling revenue	$ 50,612	$ 52,965	$ 46,661	$ 196,492	$ 174,720
Contract drilling operating cost	32,032	35,792	31,387	131,385	122,600
Operating profit from contract drilling	18,580	17,173	15,274	65,107	52,120
Add:					
Elimination of intercompany rig profit and bad debt expense	1,186	644	642	3,078	1,620
Operating profit from contract drilling before elimination of intercompany rig profit and bad debt expense	19,766	17,817	15,916	68,185	53,740
Contract drilling operating days	3,142	3,041	2,868	11,960	10,964
Average daily operating margin before elimination of intercompany rig profit and bad debt expense	$ 6,291	$ 5,859	$ 5,550	$ 5,701	$ 4,901

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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,	
	2018	2017
	(In thousands)	
Net cash provided by operating activities	$ 347,759	$ 265,956
Net change in operating assets and liabilities	(2,177)	10,855
Cash flow from operations before changes in operating assets and liabilities	$ 345,582	$ 276,811

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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, 2018	Three Months Ended December 31, 2017	Twelve Months Ended December 31, 2018	Twelve Months Ended December 31, 2017
	(In thousands except earnings per share)			
Net income (loss)	$ (76,905)	$ 89,155	$ (39,767)	$ 117,848
Income taxes	(26,376)	(79,762)	(13,996)	(57,678)
Depreciation, depletion and amortization	64,629	57,712	243,605	209,257
Impairments	147,884	—	147,884	—
Interest expense	7,816	9,527	33,494	38,334
(Gain) loss on derivatives	(22,424)	6,287	3,184	(14,732)
Settlements during the period of matured derivative contracts	(4,763)	902	(22,803)	173
Stock compensation plans	5,502	5,269	22,899	17,747
Other non-cash items	(735)	774	(2,576)	2,886
(Gain) loss on disposition of assets	(129)	826	(704)	(327)
Adjusted EBITDA	94,499	90,690	371,220	313,508
Adjusted EBITDA attributable to non-controlling interest	6,315	—	21,488	—
Adjusted EBITDA attributable to Unit Corporation	$ 88,184	$ 90,690	$ 349,732	$ 313,508
Diluted earnings (loss) per share attributable to Unit	$ (1.49)	$ 1.71	$ (0.87)	$ 2.28
Diluted earnings per share from income taxes	(0.52)	(1.53)	(0.26)	(1.11)
Diluted earnings per share from depreciation, depletion and amortization	1.13	1.11	4.36	4.04
Diluted earnings per share from impairments	2.84	—	2.84	—
Diluted earnings per share from interest expense	0.15	0.18	0.63	0.74
Diluted earnings per share from the (gain) loss on derivatives	(0.43)	0.12	0.06	(0.28)
Diluted earnings per share from the settlements during the period of matured derivative contracts	(0.09)	0.02	(0.44)	—
Diluted earnings per share from stock compensation plans	0.10	0.10	0.43	0.34
Diluted earnings per share from other non-cash items	—	0.01	(0.01)	0.06
Diluted earnings per share (gain) loss on disposition of assets	—	0.02	(0.01)	(0.01)
Adjusted EBITDA per diluted share	$ 1.69	$ 1.74	$ 6.73	$ 6.06
Weighted Shares (Denominator)	52,070	52,201	51,981	51,748

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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.