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UNIT CORPORATION REPORTS 2010 THIRD QUARTER RESULTS

Tulsa, Oklahoma . . . Unit Corporation (NYSE - UNT) reported net income of \$34.5 million, or \$0.73 per diluted share, for the three months ended September 30, 2010. For the same period in 2009, net income was \$31.4 million, or \$0.66 per diluted share. Total revenues for the third quarter of 2010 were \$218.1 million (39% contract drilling, 44% oil and natural gas, and 17% mid-stream), compared to \$167.4 million (30% contract drilling, 53% oil and natural gas, and 16% mid-stream) for the third quarter of 2009.

For the first nine months of 2010, Unit reported net income of \$102.8 million, or \$2.17 per diluted share. For the same period in 2009 it reported a net loss of \$84.0 million, or \$1.79 per diluted share. The 2009 results included a noncash ceiling test write down of \$281.2 million (\$175.1 million after tax, or \$3.72 per diluted share). The ceiling test write down reduced the carrying value of Unit's oil and natural gas properties and was required because of significantly lower commodity prices existing at the end of the first quarter 2009. Without the ceiling test write down, net income for the first nine months of 2009 would have been \$91.1 million, or \$1.93 per diluted share (see Non-GAAP Financial Measures below).

Total revenues for the first nine months of 2010 were \$629.3 million (35% contract drilling, 46% oil and natural gas, and 18% mid-stream), compared to \$532.6 million (35% contract drilling, 50% oil and natural gas, and 13% mid-stream) for the same period in 2009.

CONTRACT DRILLING SEGMENT INFORMATION

The average number of drilling rigs used in the third quarter of 2010 was 65.4, an increase of 89% over the third quarter of 2009, and an increase of 13% over the second quarter of 2010.

Per day drilling rig rates for the third quarter of 2010 averaged \$15,814, up 3% (or \$454) from the third quarter of 2009, and up 6% (or \$899) from the second quarter of 2010.

Average per day operating margin for the third quarter of 2010 was \$7,056 (before elimination of intercompany drilling rig profit of \$2.9 million). This compares to \$6,433 (before elimination of intercompany drilling rig profit of \$0.1 million) for the third quarter of 2009, an increase of 10%, or \$623. As compared to the second quarter of 2010 (\$5,101 before elimination of intercompany drilling rig profit of \$1.5 million) third quarter 2010 margin increased 38% or \$1,955 - in each case with regard to the elimination of

intercompany drilling rig profit see Non-GAAP Financial Measures below. Included in the average operating margin amount for the third quarter of 2009 was an approximated per day amount of \$1,104 for early termination fees resulting from the cancellation of long-term contracts. No early termination fees were included in the third quarter 2010 results.

For the first nine months of 2010, Unit averaged 58.2 working drilling rigs, up 47% from 39.6 during the first nine months of 2009.

Average per day operating margin for the first nine months of 2010 was \$5,649 (before elimination of intercompany drilling rig profit of \$4.7 million) as compared to \$7,403 (before elimination of intercompany drilling rig profit of \$1.2 million) for the first nine months of 2009, a decrease of 24% (in each case with regard to the elimination of intercompany drilling rig profit see Non-GAAP Financial Measures below). Included in the average operating margin amount for the first nine months of 2010 and 2009 was an approximated per day amount of \$9 and \$368, respectively, for early termination fees resulting from the cancellation of long-term contracts. Excluding early termination fees, average operating margins for the first nine months of 2010 were \$5,640 per day, a decrease of \$1,395 per day or 20% as compared to \$7,035 per day for the first nine months of 2009.

The following table illustrates Unit's drilling rig count at the end of each period and average utilization rate during the period:

	3 rd Qtr 10	2 nd Qtr 10	1 st Qtr 10	4 th Qtr 09	3 rd Qtr 09	2 nd Qtr 09	1 st Qtr 09	4 th Qtr 08	3 rd Qtr 08
Rigs	123	123	125	130	130	131	131	132	131
Utilization	54%	47%	40%	28%	26%	24%	40%	74%	85%

Larry Pinkston, Unit's Chief Executive Officer and President, said: "The third quarter of 2010 was the fourth consecutive quarter in which we increased the average number of our working drilling rigs over the previous quarter. These increases are primarily the result of increases in drilling of oil related horizontal or directional wells. Approximately 67% of our drilling rigs working today are drilling for oil or natural gas liquids and approximately 88% are drilling horizontal or directional wells. Because of the increases in demand for drilling rigs capable of drilling horizontal wells, we are building four new drilling rigs. Two of the drilling rigs we anticipate completing during the first quarter of 2011 and the remaining two sometime during the third quarter of 2011. All four of these drilling rigs are 1,500 horsepower, diesel-electric, and will be operating under long-term contracts in the Bakken play."

"During the quarter, we entered into a contract with an unaffiliated third-party under which we conveyed three of our idle mechanical drilling rigs and, in exchange, we received a 1,200 horsepower electric drilling rig and \$5.3 million. The three sold drilling rigs ranged in horsepower from 650 to 1,000. The transaction closed in October and resulted in an estimated gain of \$3.5 million. Because of this transaction, our drilling rig fleet now totals 121. Currently, 74 of our drilling rigs are under contract. Long-term contracts (contracts with original terms ranging from six months to two years in length) are in place for 43 of the 74 contracted drilling rigs. Of these contracts, eight are up for renewals at various times during the remainder of 2010, 34 are up for renewals during 2011 and one is up for renewal in 2012. We have increased our 2010 anticipated capital expenditures for this segment from \$76 million to \$130 million."

OIL AND NATURAL GAS SEGMENT INFORMATION

- Drilled 39 and 105 gross wells during the third quarter and first nine months of 2010, respectively.
- Approximately 383 MMcfe of production from its Segno field was shut-in during July of 2010 because of operational issues at a third-party processing facility.
- Secured the necessary fracing services needed to overcome by year-end the backlog of its wells waiting on completions in the Granite Wash and Marmaton plays.
- Currently anticipates it will drill 160 wells during 2010 with a revised production estimate of 59.0 to 60.0 Bcfe.

Third quarter 2010 oil production was 379,000 barrels, in comparison to 300,000 barrels for the same period of 2009, up 26%. Natural gas liquids (NGLs) production during the third quarter of 2010 was 378,000 barrels, an increase of 6% when compared to 358,000 barrels for the same period of 2009. Third quarter 2010 natural gas production was down 3% to 10.4 billion cubic feet (Bcf) compared to 10.7 Bcf for the comparable quarter of 2009. Third quarter 2010 equivalent production totaled 14.9 Bcfe, up 2% from the third quarter of 2009 and up 7% from the second quarter of 2010. The unexpected shut-in of production due to operational issues at a third-party facility that processes Unit's Segno field production negatively impacted production during the third quarter of 2010. Excluding the impact of the shut-in, third quarter 2010 production would have increased 8% over the second quarter of 2010 and 4% over the third quarter of 2009. Total production for the first nine months of 2010 was 43.0 Bcfe, down 7% over the 46.4 Bcfe produced during the same period in 2009.

Unit's average natural gas price, including the effects of hedges, for the third quarter of 2010 decreased 2% to \$5.55 per thousand cubic feet (Mcf) as compared to \$5.67 per Mcf for the third quarter of 2009. Unit's average oil price, including the effects of hedges, for the third quarter of 2010 was \$66.94 per barrel compared to \$59.55 per barrel for the third quarter of 2009. Unit's average NGLs price, including the effects of hedges, for the third quarter of 2010 was \$31.67 per barrel compared to \$22.99 per barrel for the third quarter of 2009, up 38%.

For the first nine months of 2010, Unit's average natural gas price, including the effects of hedges, increased 3% to \$5.71 per Mcf as compared to \$5.53 per Mcf for the first nine months of 2009. Unit's average oil price, including the effects of hedges, for the first nine months of 2010 was \$67.05 per barrel compared to \$54.77 per barrel during the first nine months of 2009, a 22% increase. Unit's average NGLs price, including the effects of hedges, for the first nine months of 2010 was \$35.91 per barrel compared to \$21.80 per barrel during the first nine months of 2009, a 65% increase.

For the fourth quarter of 2010, approximately 63% of Unit's anticipated average daily natural gas production is hedged, 49% of its anticipated daily oil production is hedged, and 11% of its anticipated daily NGLs production is hedged. The natural gas production is hedged under swap contracts at a comparable average NYMEX price of \$6.95. The average basis differential for the swaps is (\$0.66). Of the oil hedges, 60% are under swap contracts at an average price of \$61.36 per barrel and 40% are under a collar contract with a floor of \$67.50 per barrel and a ceiling of \$81.53 per barrel. The NGLs production is hedged under swap contracts at an average price of \$41.12 per barrel.

For 2011, Unit has hedged 15,000 MMBtu per day of its natural gas production, 2,500 Bbls per day of its oil production and 504 Bbls per day of its NGLs production. The natural gas production is hedged under swap contracts at a comparable average NYMEX price of \$5.56. The average basis differential for the swaps is (\$0.14). The oil production is hedged under swap contracts at an average price of \$80.32 per barrel. The NGLs production is hedged under swap contracts at an average price of \$40.74 per barrel.

For 2012, Unit has hedged approximately 15,000 MMBtu per day of its natural gas production and 1,500 Bbls per day of its oil production. The natural gas production is hedged under swap contracts at a comparable average NYMEX price of \$5.90. The average basis differential for the swaps is (\$0.28). The oil production is hedged under swap contracts at an average price of \$82.49 per barrel.

The following table illustrates Unit's production and certain other results for the periods indicated:

	3 rd Qtr 10	2 nd Qtr 10	1 st Qtr 10	4 th Qtr 09	3 rd Qtr 09	2 nd Qtr 09	1 st Qtr 09	4 th Qtr 08	3 rd Qtr 08
Production, Bcfe	14.9	14.0	14.1	14.3	14.7	15.4	16.3	16.8	15.9
Production, MMcf/day	162.2	153.3	156.8	155.8	159.4	169.6	180.9	182.6	172.4
Realized price, Mcfe (1)	\$6.36	\$6.37	\$6.82	\$6.12	\$5.92	\$5.75	\$5.48	\$6.21	\$9.49
Wells Drilled	39	39	27	37	21	16	21	67	82
Success Rate	85%	92%	96%	92%	90%	100%	90%	90%	89%

(1) Realized price includes oil, natural gas liquids, natural gas and associated hedges.

In the Marmaton horizontal oil play located in Beaver County, Oklahoma, Unit added a second company rig in early September and plans to keep two drilling rigs working during the fourth quarter and throughout 2011. At the end of the third quarter, Unit was waiting on the completion of ten horizontal wells. The completion of these wells during the third quarter was delayed due to the lack of availability of third party completion services. Unit was able to successfully frac eight of the 10 wells by the end of October. The first three wells are online and producing at peak daily rates of 497, 484, and 169 barrels of oil equivalent per day with an average working interest of 91%. Completion of the remaining five wells started in the latter part of October. Unit has scheduled two frac dates in November, three in December and is currently working to secure about three frac dates per month for 2011 in this play.

In connection with its drilling operations in the Marmaton, Unit has been able to reduce the average drilling days from 27 to 20 per well. Unit continues to improve the drilling process, resulting in the last four wells being drilled in an average of 13 days, which equates to a cost reduction of approximately \$630,000 per well when compared to 27 days to drill.

In the Granite Wash play located in the Texas Panhandle, the company added a fourth Unit rig in mid September as part of its horizontal well program in this play. During the third quarter, Unit completed three horizontal wells, all from the Granite Wash "B" interval. The Webb A-4H (83% working interest (WI)) was fracture stimulated in late September with subsequent first gas sales in early October. The well is currently producing approximately 691 barrels of oil per day, 449 barrels of NGLs per day, and 4.1 MMcf per day with 1,200 pounds of flowing casing pressure or an equivalent rate of 10.9 MMcf per day. The rate is continuing to increase as a result of increasing the choke size and recovering more of the frac load water. In the same prospect, the Webb #3H (83% WI) was also fracture stimulated in late September, but due to a down-hole restriction the well does not appear to be producing at full capacity. The peak daily rate for this well is currently approximately 165 barrels of oil per day, 240 barrels of NGLs per day and 2.2 MMcf per day or an equivalent rate of 4.6 MMcf per day. Plans are to drill out the packer ports in the wellbore lateral in the next couple of weeks with the anticipation that rates from this well will increase to a similar rate currently being produced from the Webb A-4H. The Temple "A" 1H (48% WI) had first sales in late August at a peak daily rate of approximately 182 barrels of oil per day, 105 barrels of NGLs per day and 0.96 MMcf per day or an equivalent rate of 2.8 MMcf per day. The lower rate is attributable to a shorter lateral length of only 2,000 feet and higher water cut due to communication during the fracture treatment with a wet sand located beneath the pay sand. A submersible pump was recently installed to help lift the water in an attempt to increase the production rate of the well. In late October, Unit frac'd two additional horizontal Granite Wash "A" wells. Both are currently flowing back the frac water load. In addition, Unit secured two frac dates in both November and December to complete wells currently being drilled. In total, Unit anticipates completing six Granite Wash horizontal wells during the fourth quarter 2010 as compared to one during the first quarter, one in the second quarter and three in the third quarter. We plan to run a three to four rig horizontal Granite Wash program in 2011 which should result in two to three wells coming online per month.

In the Segno play located in Southeast Texas, Unit is running two Unit rigs with plans to continue that program through most of 2011. During the third quarter, Unit completed three new producers from various Wilcox zones. The Black Stone "G" #1 (100% WI) had first sales in late August at an initial rate of approximately 3.5 MMcf per day, 120 barrels of oil per day and 250 barrels of NGLs per day with 6,600 pounds of flowing tubing pressure or an equivalent rate of 5.7 MMcf per day. The Wildwood #A-3 (100% WI) was dual completed in late October from two Upper Wilcox zones flowing at a combined rate of approximately 300 barrels of oil per day, 149 barrels of NGLs per day and 2.1 MMcf per day or an equivalent rate of 5.5 MMcf per day. The Wildwood B #3 (100% WI) also had first sales in late October flowing approximately 370 barrels of oil per day, 24 barrels of NGLs per day and 0.34 MMcf per day or an equivalent rate of 2.7 MMcf per day. In addition, the BP "L" #1 (100% WI) was completed during the second quarter but has been shut-in pending a pipeline connection. This well should be online in mid November with an estimated initial pre frac rate of approximately 2.1 MMcf per day, 90 barrels of oil per day and 149 barrels of NGLs per day.

In Shelby County, Texas, a second horizontal Haynesville well, the KC GU #1H (59% WI) has drilled 4,000 feet of Haynesville lateral and is scheduled to be frac'd in early February 2011. In Harrison County, Texas, the Double K #1H (33% WI) had first gas sales in late September from the Cotton Valley sand at initial rates of approximately 8.8 MMcf per day and 127 barrels of oil per day with 2,120 pounds flowing tubing pressure. The lateral length was 4,000 feet and the well was fracture stimulated in 10 stages and 2.3 million pounds of sand. An offset is planned to begin before the end of this year.

In the Bakken play located in North Dakota, the Henderson #4-25H (10% WI) was completed in early August at an initial rate of approximately 1,313 barrels of oil per day. The Andrecovich #5-16/17H (18% WI) had first oil sales in mid September at an initial peak rate of approximately 2,429 barrels of oil per day. The State #1-16/21H (13% WI) had initial sales in late October at a peak rate of approximately 2,579 barrels of oil per day. Unit anticipates working two to three rigs drilling on its North Dakota Bakken leasehold during the fourth quarter and into 2011.

In the Panola prospect, located in Southeast Oklahoma, the Austin #1 (31% WI) had first gas sales in late September from the Spiro sand formation at an initial rate of approximately 5.1 MMcf per day with 2,645 pounds of flowing tubing pressure.

Pinkston said: "The first nine months of 2010 has been challenging for us with regard to carrying out the work we had planned for our 2010 drilling program. During the first, second, and third quarters of 2010, we drilled 27 wells, 39 wells and 39 wells, respectively. Our first quarter drilling activity was hampered by unusually wet weather, especially in the Texas Panhandle Granite Wash play, and operational delays as we shifted to drilling primarily horizontal wells. The delays in getting wells online are primarily due to delays in securing fracing services and connections to gathering systems. During the third quarter, we undertook steps that we now feel will allow us to obtain these required services so that by the end of the year we should have eliminated the unusually large backlog of our well completions, especially in the Granite Wash and Marmaton plays. Additionally, we have scheduled fracing services for 2011 for all the wells we currently anticipate we will drill in the Granite Wash play. As a result of timing issues regarding the completion of wells scheduled to begin production in the third quarter and early in the fourth quarter, we are revising our 2010 production guidance to approximately 59.0 to 60.0 Bcfe, although actual results will continue to be subject to the timing of third party services. The number of wells we plan to participate in drilling and the level of capital expenditures for 2010 is 160 wells and \$344 million, respectively."

MID-STREAM SEGMENT INFORMATION

- Increased by 3% and 8%, respectively, its third quarter 2010 per day liquids sold volumes and processing volumes over the same period in 2009.
- Committed to build a 16-mile pipeline and a compressor station in Preston County, West Virginia and signed an agreement to transport gas on this system for an unaffiliated third party.

Third quarter of 2010 per day processing volumes were 84,175 MMBtu while liquids sold volumes were 260,519 gallons per day, an increase of 8% and 3%, respectively, over the third quarter of 2009. Third quarter 2010 per day gathering volumes were 183,161 MMBtu, up 2% over the third quarter of 2009. Operating profit (as defined in the Selected Financial and Operational Highlights) for the third quarter was \$6.7 million, an increase of 8% from the third quarter of 2009, primarily due to increased processing margins resulting from increased liquids prices.

For the first nine months of 2010, processing volumes were 81,157 MMBtu per day and liquids sold volumes were 264,679 gallons per day, an increase of 8% and 12%, respectively, over the first nine months of 2009. Gathering volumes for the first nine months of 2010 were 182,390 MMBtu per day, a 2% decrease over the first nine months of 2009.

The following table illustrates certain results from this segment's operations for the periods indicated:

	3 rd Qtr 10	2 nd Qtr 10	1 st Qtr 10	4 th Qtr 09	3 rd Qtr 09	2 nd Qtr 09	1 st Qtr 09	4 th Qtr 08	3 rd Qtr 08
Gas gathered MMBtu/day	183,161	183,858	180,117	177,145	179,047	187,666	192,320	187,585	195,914
Gas processed MMBtu/day	84,175	82,699	76,513	77,501	77,923	75,481	72,650	72,491	71,260
Liquids sold Gallons/day	260,519	279,736	253,707	263,668	251,830	239,121	218,762	197,428	199,805

Unit's mid-stream segment operates three natural gas treatment plants, owns and operates eight processing plants, 34 active gathering systems and approximately 853 miles of pipeline.

Pinkston said: "Gas processed volumes, liquids sold volumes as well as gas gathered volumes all continued to increase and remained strong in the third quarter. We are in the final stages of completing a 50 MMcf per day turbo-expander natural gas processing plant at our Hemphill facility in Canadian, Texas. This gas processing plant should be completed and operational in the fourth quarter of 2010. On completion of this new natural gas processing plant, the total processing capacity at our Hemphill facility will increase to approximately 100 MMcf per day. In connection with our Appalachian operations, we recently committed to build a 16-mile, 16" pipeline and a compressor station in Preston County, West Virginia, which will have a capacity of approximately 200 MMcf per day. Preliminary right-of-way and environmental work is nearing completion and construction is scheduled to begin during the first quarter of 2011 with the facility being operational by mid-2011. We have signed an agreement to transport gas on this system for an unaffiliated third party."

FINANCIAL INFORMATION

Unit ended the third quarter of 2010 with working capital of \$35.5 million, long-term debt of \$135.0 million, and a debt to capitalization ratio of 7%. Under its credit facility, the amount available to be borrowed is the lesser of the amount the company elects as the commitment amount (currently \$325 million) or the value of the borrowing base as determined by the lenders (currently \$500 million), but, in either event, not to exceed the maximum credit facility amount of \$400 million.

MANAGEMENT COMMENT

Larry Pinkston said: "We are benefitting from increases in oil related demand for drilling by exploration and production companies as we add to our existing drilling rig fleet and refurbish and upgrade certain drilling rigs. Our mid-stream segment continues to grow with new pipeline projects and the expansion of existing facilities. While our overall 2010 exploration activities have progressed slower than we would like, we believe we have overcome many of the obstacles and the focus of our exploration operations will be on oil and natural gas liquids rich plays like the Granite Wash and Marmaton."

WEBCAST

Unit will webcast its third quarter earnings conference call live over the Internet on November 4, 2010 at 10:00 a.m. Central Time (11:00 a.m. Eastern). To listen to the live call, please go to www.unitcorp.com at least fifteen minutes prior to 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 twelve months.

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 listed on the New York Stock Exchange under the symbol UNT. For more information about Unit Corporation, visit its website at <http://www.unitcorp.com>.

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 or anticipates will or may occur in the future are forward-looking statements. A number of risks and uncertainties could cause actual results to differ materially from these statements, including the impact that the current decline in wells being drilled will have on production and drilling rig utilization, productive capabilities of the Company's wells, future demand for oil and natural gas, future drilling rig utilization and dayrates, projected growth of the Company's oil and natural gas production, oil and gas reserve information, as well as its ability to meet its future reserve replacement goals, anticipated gas gathering and processing rates and throughput volumes, the prospective capabilities of the reserves associated with the Company's inventory of future drilling sites, availability and timing of obtaining third party services used in the drilling or completion of its oil and gas wells, anticipated oil and natural gas prices, the number of wells to be drilled by the Company's exploration segment, development, operational, implementation and opportunity risks, possible delays caused by limited availability of third party services needed in the course of its operations, possibility of future growth opportunities, and other factors described from time to time in the Company's publicly available SEC reports. The Company assumes no obligation to update publicly such forward-looking statements, whether as a result of new information, future events or otherwise.

Unit Corporation
Selected Financial and Operations Highlights
(In thousands except per share and operations data)

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2010	2009	2010	2009
Statement of Operations:				
Revenues:				
Contract drilling	\$ 85,004	\$ 49,801	\$ 217,919	\$ 188,383
Oil and natural gas	96,562	88,894	286,751	267,399
Gas gathering and processing	37,429	26,228	114,908	71,604
Other, net	(879)	2,507	9,691	5,180
Total revenues	218,116	167,430	629,269	532,566
Expenses:				
Contract drilling:				
Operating costs	45,406	29,456	132,847	109,565
Depreciation	18,469	10,923	48,700	33,803
Oil and natural gas:				
Operating costs	27,092	20,781	75,943	62,846
Depreciation, depletion and amortization	30,091	25,645	81,746	89,800
Impairment of oil and natural gas properties	---	---	---	281,241
Gas gathering and processing:				
Operating costs	30,743	20,012	92,407	59,888
Depreciation and amortization	3,823	3,995	11,746	12,166
General and administrative	6,637	5,506	19,372	17,088
Interest, net	---	1	---	539
Total expenses	162,261	116,319	462,761	666,936
Income (Loss) Before Income Taxes	55,855	51,111	166,508	(134,370)
Income Tax Expense (Benefit):				
Current	(8,553)	8,571	(2,488)	9,818
Deferred	29,917	11,091	66,177	(60,175)
Total income taxes	21,364	19,662	63,689	(50,357)
Net Income (Loss)	\$ 34,491	\$ 31,449	\$ 102,819	\$ (84,013)
Net Income (Loss) per Common Share:				
Basic	\$ 0.73	\$ 0.67	\$ 2.18	\$ (1.79)
Diluted	\$ 0.73	\$ 0.66	\$ 2.17	\$ (1.79)
Weighted Average Common Shares Outstanding:				
Basic	47,358	47,011	47,217	46,980
Diluted	47,495	47,419	47,384	46,980

	September 30, 2010	December 31, 2009
Balance Sheet Data:		
Current assets	\$ 158,160	\$ 128,095
Total assets	\$ 2,544,885	\$ 2,228,399
Current liabilities	\$ 122,680	\$ 105,147
Long-term debt	\$ 135,000	\$ 30,000
Other long-term liabilities	\$ 90,774	\$ 81,126
Deferred income taxes	\$ 513,563	\$ 446,316
Shareholders' equity	\$ 1,682,868	\$ 1,565,810

	Nine Months Ended September 30, 2010		2009	
Statement of Cash Flows Data:				
Cash Flow From Operations before Changes in Operating Assets and Liabilities (1)	\$	309,861	\$	282,260
Net Change in Operating Assets and Liabilities		(25,965)		140,310
Net Cash Provided by Operating Activities	\$	<u>283,896</u>	\$	<u>422,570</u>
Net Cash Used in Investing Activities	\$	(393,804)	\$	(204,637)
Net Cash Provided by (Used in) Financing Activities	\$	109,901	\$	(217,371)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Contract Drilling Operations Data:				
Rigs Utilized	65.4	34.6	58.2	39.6
Operating Margins (2)	47%	41%	39%	42%
Operating Profit Before Depreciation (2) (\$MM)	\$ 39.6	\$ 20.3	\$ 85.1	\$ 78.8

Oil and Natural Gas Operations Data:				
Production:				
Oil – MBbls	379	300	1,002	991
Natural Gas Liquids - MBbls	378	358	1,143	1,142
Natural Gas - MMcf	10,385	10,713	30,121	33,575
Average Prices:				
Oil price per barrel received	\$ 66.94	\$ 59.55	\$ 67.05	\$ 54.77
Oil price per barrel received, excluding hedges	\$ 72.52	\$ 64.75	\$ 74.11	\$ 51.76
NGLs price per barrel received	\$ 31.67	\$ 22.99	\$ 35.91	\$ 21.80
NGLs price per barrel received, excluding hedges	\$ 31.27	\$ 25.23	\$ 35.70	\$ 22.51
Natural Gas price per Mcf received	\$ 5.55	\$ 5.67	\$ 5.71	\$ 5.53
Natural Gas price per Mcf received, excluding hedges	\$ 3.94	\$ 2.96	\$ 4.27	\$ 3.06
Operating Profit Before DD&A and Impairment (2) (\$MM)	\$ 69.5	\$ 68.1	\$ 210.8	\$ 204.6

Mid-Stream Operations Data:				
Gas Gathering - MMBtu/day	183,161	179,047	182,390	186,296
Gas Processing - MMBtu/day	84,175	77,923	81,157	75,371
Liquids Sold – Gallons/day	260,519	251,830	264,679	236,692
Operating Profit Before Depreciation and Amortization (2) (\$MM)	\$ 6.7	\$ 6.2	\$ 22.5	\$ 11.7

(1) The company considers its cash flow from operations before changes in operating assets and liabilities an important measure in meeting the performance goals of the company (see Non-GAAP Financial Measures below).

(2) Operating profit before depreciation is calculated by taking operating revenues by segment less operating expenses excluding depreciation, depletion, amortization and impairment, general and administrative and interest expense. Operating margins are calculated by dividing operating profit by segment revenue.

Non-GAAP Financial Measures

We report our financial results in accordance with generally accepted account principles (“GAAP”). We believe certain non-GAAP performance measures provide users of our financial information and our management additional meaningful information to evaluate the performance of our company.

This press release includes net income excluding the effect of the impairment of our oil and natural gas properties, earnings per share excluding the effect of the impairment of our oil and natural gas properties, cash flow from operations before changes in operating assets and liabilities and our drilling segment’s average daily operating margin before elimination of drilling rig profit.

Below is a reconciliation of GAAP financial measures to non-GAAP financial measures for the three and nine months ended September 30, 2010 and 2009. Non-GAAP financial measures should not be considered by themselves or a substitute for our results reported in accordance with GAAP.

Unit Corporation Reconciliation of Net Income and Earnings per Share Excluding the Effect of Impairment of Oil and Natural Gas Properties

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(In thousands except per share amounts)			
Net income excluding impairment of oil and natural gas properties:				
Net income (loss)	\$ 34,491	\$ 31,449	\$ 102,819	\$ (84,013)
Add:				
Impairment of oil and natural gas properties (net of income tax)	---	---	---	175,072
Net income excluding impairment of oil and natural gas properties	\$ 34,491	\$ 31,449	\$ 102,819	\$ 91,059
Diluted earnings per share excluding impairment of oil and natural gas properties:				
Diluted earnings per share	\$ 0.73	\$ 0.67	\$ 2.17	\$ (1.79)
Add:				
Diluted earnings per share from impairment of oil and natural gas properties	---	(0.01)	---	3.72
Diluted earnings per share excluding impairment of oil and natural gas properties	\$ 0.73	\$ 0.66	\$ 2.17	\$ 1.93

We have included the net income excluding impairment of oil and natural gas properties and diluted earnings per share excluding impairment of oil and natural gas properties because:

- We use 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.
- The impairment of oil and natural gas properties does not occur on a recurring basis and the amount and timing of impairments cannot be reasonably estimated for budgeting purposes and is therefore typically not included for forecasting operating results.

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

	Nine Months Ended	
	September 30,	
	2010	2009
	(In thousands)	
Net cash provided by operating activities	\$ 283,896	\$ 422,570
Subtract:		
Net change in operating assets and liabilities	(25,965)	140,310
Cash flow from operations before changes in operating assets and liabilities	<u>\$ 309,861</u>	<u>\$ 282,260</u>

We have included the cash flow from operations before changes in operating assets and liabilities because:

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

Unit Corporation
Reconciliation of Average Daily Operating Margin Before Elimination of Rig Profit

	Three Months	Three Months Ended		Nine Months Ended	
	Ended June 30,	September 30,		September 30,	
	2010	2010	2009	2010	2009
	(In thousands except day and daily data)				
Contract drilling revenue	\$ 72,061	\$ 85,004	\$ 49,801	\$ 217,919	\$ 188,383
Contract drilling operating cost	46,541	45,406	29,456	132,847	109,565
Operating profit from contract drilling	25,520	39,598	20,345	85,072	78,818
Add:					
Elimination of intercompany rig profit and bad debt expense	1,453	2,888	107	4,718	1,172
Operating profit from contract drilling before elimination of intercompany rig profit	26,973	42,486	20,452	89,790	79,990
Contract drilling operating days	5,288	6,021	3,179	15,894	10,805
Average daily operating margin before elimination of rig profit	<u>\$ 5,101</u>	<u>\$ 7,056</u>	<u>\$ 6,433</u>	<u>\$ 5,649</u>	<u>\$ 7,403</u>

We have included the average daily operating margin before elimination of rig profit because:

- Our management uses the measurement to evaluate the cash flow performance of our 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 our company.