Goodrich Petroleum

Goodrich Petroleum Announces Year-End And Fourth Quarter Financial Results And Operational Update

PR Newswire
HOUSTON

HOUSTON, Feb. 20, 2013 /PRNewswire/ -- Goodrich Petroleum Corporation (NYSE: GDP) today announced financial and operating results for the year and fourth quarter ended December 31, 2012.

- **Adjusted EBITDAX grew 5 percent sequentially and 18 percent from the prior year period to a record $50.5 Million for the quarter, while Discretionary Cash Flow grew by 8 percent sequentially and 15 percent from the prior year period to $39.9 Million for the quarter**
- **Adjusted Revenues, including realized gain on derivatives of $17.1 Million, totaled $65.4 Million for the quarter**
- **Oil production grew by 12.5% sequentially and 47% over the prior year period to an average of 3,600 barrels of oil per day for the quarter, which comprised 30% of total production for the quarter. Oil production for the year increased by 70% over the prior year**
- **Tuscaloosa Marine Shale: The Crosby 12H-1 well (50% WI), the Company's initial operated completed well in the field, had a peak, 24-hour average rate of approximately 1,300 barrels of oil equivalent ("BOE") per day, comprised of approximately 1,200 barrels of oil and 600 Mcf of natural gas per day. The well has averaged 1,200 BOE per day over 15 days, comprised of 1,100 barrels of oil and 600 Mcf of natural gas per day, and is currently producing at 1,200 BOE per day.**

(See accompanying tables at the end of this press release that reconcile Adjusted Revenue, Adjusted EBITDAX, discretionary cash flow, cash operating margin and adjusted operating income, which are non-GAAP financial measures, to their most directly comparable GAAP financial measure.)

CASH FLOW

Earnings before interest, taxes, DD&A, non-cash general and administrative expenses and exploration (" Adjusted EBITDAX") increased by 18% to $50.5 million in the quarter, compared to $42.7 million in the prior year period and $48.0 million in the prior quarter. Adjusted EBITDAX for the year increased by 9% to $184.0 million versus $169.2 million in the prior year period.

Discretionary cash flow ("DCF"), defined as net cash provided by operating activities before changes in working capital, increased by 15% to $39.9 million in the quarter, compared to $34.8 million in the prior year period and $36.9 million in the prior quarter. DCF increased by 6% to $141.5 million for the year, versus $133.8 million in the prior year period. Net cash provided by operating activities for the year increased by 28% to $173.8 million, compared to $136.3 million for the prior year period.

(See accompanying tables at the end of this press release that reconcile Adjusted EBITDAX and DCF, each of which are non-GAAP financial measures, to their most directly comparable GAAP financial measure.)

NET INCOME

The Company announced a net loss applicable to common stock of $77.2 million for the quarter, or ($2.12) per basic share, versus a net loss applicable to common stock of $23.8 million, or ($0.66) per basic share in the prior year period. The quarter was negatively impacted by non-recurring expenses of $58.0 million, comprised of $45.2 million for impairment of natural gas assets and $12.8 million of exploration expense associated with the Company's partial abandonment of a well in one of its fields. The Company announced a net loss applicable to common stock of $90.2 million for 2012, or ($2.48) per basic share, versus a net loss applicable to common stock of $37.8 million, or ($1.05) per basic share for 2011.

(See accompanying tables at the end of this press release that reconcile adjusted net loss applicable to common stock, a non-GAAP measure, to its most directly comparable GAAP financial measure.)

PRODUCTION

Production for the quarter was 6.6 billion cubic feet equivalent ("Bcfe"), or an average of 71,800 Mcfe per day, versus 10.0 Bcfe, or an average of 108,200 Mcfe per day in the prior year period. Oil production for the quarter totaled 329,000 barrels of oil, or an average of approximately 3,600 barrels per day, versus 225,000 barrels of oil, or 2,450 barrels per day, in the prior year period. Peak rate for the quarter was approximately 4,350 barrels of oil per day. Natural gas production for the quarter totaled 4.6 Bcf, or an average of 50,300 Mcf per day. Production for the year totaled 1.1 million barrels of oil, a 70% increase over 2011, and 24.8 Bcf of natural gas, or an average of 85,800 Mcfe per day.

REVENUES

Revenues for the quarter were $48.2 million versus $51.4 million in the prior year period. Revenues, including realized gain on derivatives not designated as hedges of $17.1 million for the quarter, would have been $65.4 million. Average realized price per unit for the quarter, was $7.24 per Mcfe, versus $5.18 per Mcfe in the prior year period. When factoring in the realized gain on derivatives not designated as hedges, average realized price per unit was $9.83 per Mcfe, versus $6.17 in the prior year period.

Revenues for the year totaled $180.8 million, versus $201.1 million in the prior year period. Revenues, including realized gain on derivatives not designated as hedges of $73.2 million for the year, would have been $254.0 million. Average realized price per unit for the year, was $5.75 per Mcfe, versus $5.01 per Mcfe in the prior year period. When factoring in the realized gain on derivatives not designated as hedges, average realized price per unit was $8.08 per Mcfe, versus $5.79 per Mcfe in the prior year period.

OPERATING EXPENSES

Lease operating expense ("LOE") was $4.7 million in the quarter, or $0.71 per Mcfe, versus $5.9 million, or $0.60 per Mcfe in the prior year period. For the year, LOE totaled $25.9 million, or $0.83 per Mcfe, versus $21.5 million, or $0.54 per Mcfe in the prior year period.

Production and other taxes for the quarter were $2.4 million, or $0.36 per Mcfe, versus $1.3 million, or $0.13 per Mcfe in the prior year period. For the year, production and other taxes totaled $8.1 million, or $0.26 per Mcfe, versus $5.5 million, or $0.14 per Mcfe in the prior year period.

Transportation and processing expense was $2.8 million, or $0.43 per Mcfe in the quarter, versus $5.5 million, or $0.55 per Mcfe in the prior year period. For the year, transportation expense was $13.9 million, or $0.44 per Mcfe, versus $13.0 million, or $0.32 per Mcfe in the prior year period.

Depreciation, depletion and amortization ("DD&A") expense for the quarter totaled $37.1 million, or $5.62 per Mcfe, versus $38.6 million, or $3.87 per Mcfe in the prior year period. DD&A expense for the year totaled $141.2 million, or $4.50 per Mcfe, versus $131.8 million, or $3.29 per Mcfe for the prior year period.

Exploration expense was $16.4 million, or $2.48 per Mcfe for the quarter, versus $1.9 million, or $0.19 per Mcfe in the prior year period. Exploration expense for the year was $23.1 million, or $0.74 per Mcfe, versus $8.3 million, or $0.21 per Mcfe in the prior year. Approximately $12.8 million or 78% of exploration expense for the quarter and 56% for the year was associated with the dry hole expense related to the Denkmann 33H-1 mechanical failure.

Impairment expense was $45.2 million, or $6.84 per Mcfe for the quarter, versus $6.9 million, or $0.69 per Mcfe in the prior year period. Impairment expense for the year was $47.8 million, or $1.52 per Mcfe, versus $8.1 million, or $0.20 per Mcfe during the prior year period. Impairment expense during the quarter was mostly due to the impact of falling natural gas prices on our Angelina River trend field in Texas.

General and Administrative ("G&A") expense was $7.2 million, or $1.09 per Mcfe in the quarter, versus $8.0 million, or $0.80 per Mcfe in the prior year period. For the quarter, the Company recorded non-cash G&A expenses related to stock based compensation for its officers and employees of $2.2 million, or $0.33 per Mcfe, versus $2.0 million, or $0.20 per Mcfe in the prior year period. For the year, G&A expense totaled $28.9 million, or $0.92 per Mcfe, versus $29.8 million, or $0.74 per Mcfe in the prior year period. Non-cash, stock based compensation for the year was 24% of G&A expenses, or $6.9 million, which was $0.22 per Mcfe, versus $6.5 million, or $0.16 per Mcfe for the prior year period.

OPERATING INCOME

Operating income, defined as revenues minus operating expenses, totaled a loss of $67.1 million for the quarter versus an operating loss of $16.9 million for the prior year period. Operating income was negatively impacted by $58.0 million of non-recurring, non-cash expenses in the quarter. Operating income for the year was a loss of $63.7 million versus an operating loss of $17.1 million for the prior year period.

(See accompanying tables at the end of this press release that reconcile adjusted operating income, a non-GAAP financial measure to its most directly comparable GAAP financial measure.)

INTEREST EXPENSE

Interest expense for the quarter was $13.1 million, or $1.98 per Mcfe, versus $12.5 million, or $1.26 per Mcfe in the prior year period. Non-cash interest expense associated with the Company's long term debt comprised 26% of the total, or $3.4 million ($0.52 per Mcfe). For the year, interest expense was $52.4 million, or $1.67 per Mcfe, versus $49.4 million, or $1.23 per Mcfe in the prior year. Non-cash interest expense comprised 24% of the total for the year, or $12.8 million ($0.41 per Mcfe).

CAPITAL EXPENDITURES

Capital expenditures for the quarter were $57.2 million, of which $54.0 million was spent on drilling and completion costs and $3.1 million on leasehold acquisition, facilities and other expenditures. For the full year 2012, capital expenditures totaled $250.7 million, of which $218.7 million was for drilling and completion costs (90% oil directed activities) and $32.0 million was for leasehold, infrastructure and other miscellaneous expenditures. Drilling and completion expenditures of $218.7 million were comprised of $94.6 million for wells drilled in 2012 that had new reserve additions, $73.2 million, or 33% of the Company's drilling and completion capital expenditures for the year, for the conversion of 16 proved undeveloped reserve locations to proved developed reserves in 2012, $28.5 million for wells with drilling and/or completion operations in 2012 that did not have reserves booked at year-end and $22.4 million of carry-over drilling and completion costs from wells drilled in prior years.

YEAR-END RESERVES

The Company's proved oil and natural gas reserves as of December 31, 2012 were 333.1 Bcfe, versus 490 Bcfe in the prior year period. The Company incurred negative reserve revisions of 121 Bcfe of natural gas reserves at year-end that were on the books at year-end 2011 primarily related to the loss of proved undeveloped natural gas reserves, mainly in Northwest Louisiana and East Texas areas, as a result of such reserves being uneconomic under SEC pricing. The Company also sold 36.1 Bcfe during the year in an asset sale of a non-core property. Year-end proved reserves were 76% natural gas, 24% oil and liquids (an increase from 17% at year-end 2011) and 48% developed. The present value, using a 10% discount rate of the future net cash flows before income taxes of the proved reserves ("PV-10"), was $359.1 million, using SEC pricing of $2.85 per MMBtu for natural gas and $94.71 per barrel of oil. At current five year futures NYMEX pricing of $90.13 per barrel of oil (WTI) and $4.17 per MMBtu of natural gas, the year-end proved reserves would have been 442 Bcfe and the related PV-10 would have been $530 million. Year-end PV-10 of proved reserves is a non-GAAP financial measure. Please refer to "Other Information" section for additional disclosure and nformation.

The Company had proved new reserve additions from its oil directed activities in 2012 of 5.40 million BOE (32.4 Bcfe) and proved developed reserve additions, adjusted for the conversion of proved undeveloped reserve locations to proved developed reserves, of 5.87 million BOE (35.2 Bcfe). The Company had approximately $202.1 million of net drilling and completion capital expenditures associated with these 2012 wells, for an adjusted organic finding and development cost of $6.23 per Mcfe ($37.43 per BOE). Adjusted proved developed finding and development cost for 2012 wells was $5.74 per Mcfe ($34.45 per BOE). Approximately 90% of the drilling and completion capital expenditures associated with 2012 wells were from oil-focused activities.

The Company's successful Eagle Ford Shale drilling program was the primary driver of the growth in proved oil and liquids reserves in 2012.

The following table reflects the changes in the proved reserve estimates since year-end 2011:

	Proved Reserves (Bcfe)	Proved Developed Reserves (Bcfe)
Reserves at December 31, 2011	489.8	208.5
Production	(32.2)	(32.2)
Divestitures	(36.1)	(30.7)
Reserve Additions(1)	32.4	35.2
Revisions – Price and Technical	(120.9)	(22.4)
Reserves at December 31, 2012	333.1	158.4
2012 Reserve Replacement Ratio (%)(2)	100%	109%
2012 Net Cash Drilling and Completion Capital Expenditures (non-GAAP)(3)		$202.1 MM
2012 Finding and Development Costs ($/Mcfe)(4)		$6.23 ($37.43/BOE)
2012 Proved Developed Finding & Development Costs ($/Mcfe)(5)		$5.74 ($34.45/BOE)

(1) Proved Developed Reserve Additions includes the conversion of Proved Undeveloped Reserves to Proved Developed Reserves.
(2) Reserve Replacement Ratio is calculated by dividing Reserve Additions (before price and technical revisions) by Production.
(3) See Net Cash Drilling and Completion Capital Expenditures (non-GAAP) in "Other Information" section for additional disclosure and information.
(4) Finding and Development Costs per Mcfe is calculated by dividing Net Cash Drilling and Completion Capital Expenditures (non-GAAP) for wells drilled in 2012 by total proved reserve additions (before price and technical revisions).
(5) Proved Developed Finding and Development Costs per Mcfe is calculated by dividing Net Cash Drilling and Completion Capital Expenditures for wells drilled in 2012 by Proved Developed Reserve Additions (before price and technical revisions).

The reserve report was prepared by Netherland, Sewell & Associates, Inc.

CRUDE OIL AND NATURAL GAS DERIVATIVES

The Company realized a gain of $17.1 million on its derivatives not designated as hedges and an unrealized loss of $12.6 million, for a net gain on derivatives of $4.6 million for the quarter.

During the quarter, the Company hedged an additional 2,000 barrels of oil per day for 2013, bringing the total hedged oil volumes for 2013 to 3,500 barrels of oil per day at a blended average price of $94.50 per barrel.

LIQUIDITY

The Company exited the year with $1.2 million in cash and $95.0 million drawn on its senior bank revolving credit facility, providing $116.2 million of available liquidity as the Company entered 2013. The Company's borrowing base is currently $210 million, with a new borrowing base expected in the second quarter. The Company expects to finance the vast majority of its 2013 capital expenditure budget with cash on hand and increasing cash flow driven by growth in oil volumes.

OPERATIONAL UPDATE

For the quarter, the Company conducted drilling operations on 14 gross (8 net) wells, of which 11 gross (7 net) were in the Eagle Ford and 3 gross (1 net) were in the Tuscaloosa Marine Shale Trend. A total of 9 gross (7 net) wells were added to production during the quarter, of which 8 gross (5 net) were in the Eagle Ford. For the year, the Company conducted drilling operations on

46 gross (27 net) wells, with a 100% success rate. As of December 31, 2012, the Company had 20 gross (11 net) wells waiting on completion, with 13 gross (6 net) in the Haynesville Shale Trend and 7 gross (5 net) in the Eagle Ford Shale Trend.

Tuscaloosa Marine Shale Trend ("TMS")

The Company previously reported production results on its Crosby 12H-1 (50% WI), the initial operated well completed in the field, at a then 24-hour peak production rate of 1,150 BOE per day on a 15/64 choke with 2,700 psi. The well improved after the announcement, and achieved a 24-hour peak rate of 1,300 BOE and has averaged 1,200 BOE per day over the initial 15 day period, comprised of 1,100 barrels of oil and 600 Mcf of gas per day. Based on the success of the Crosby well and the Company's increasing confidence in the economic potential of the play, the Company will accelerate the timing of its next operated well and now anticipates spudding its Smith 29H-1 (~ 75% WI) well in Amite County, Mississippi in April, and as previously stated, has increased its 2013 allocation of capital to the play to $50 million, which is the higher end of its guidance. Upon additional funding, the Company will consider accelerating its activity level further in the TMS.

The Company is currently participating as a non-operator in the completion of the Ash 31H-1 (12% WI) and Ash 31H-2 (12% WI) wells in Amite County, Mississippi. The wells, which are currently being fracked, are the initial wells in which the Company has participated that have landed above the zone that has caused wellbore instability.

The Company is currently participating as a non-operator in two development wells, the Anderson 17H-2 (7% WI) and Anderson 17H-3 (7% WI) wells.

Eagle Ford Shale Trend, LaSalle and Frio Counties, Texas

In the Eagle Ford Shale Trend, the Company conducted drilling operations on 11 gross (7 net) wells in the quarter, and expects to drill 24 – 28 gross (16 – 19 net) wells in 2013. The Company has reduced its drill time on recent wells by approximately 57% from the initial wells drilled in the field, to 10 days for an average 6,000 foot lateral, which along with a reduction in frac costs, has substantially decreased the well costs and increased the well count for the year.

Haynesville Shale Trend

The Company expects to complete 13 gross (6 net) previously drilled Haynesville Shale wells in the first half of 2013, comprised of 12 gross (5 net) non-operated wells in North Louisiana and 1 gross (1 net) operated well in the Angelina River Trend. Total capital expenditures are expected to be approximately $22 million to complete these wells. Assuming timely completion, the Company expects to grow natural gas volumes during 2013 from these completions by approximately 10%.

OTHER INFORMATION

In this press release, the Company refers to several non-GAAP financial measures, including Adjusted EBITDAX, DCF, drilling and completion capital expenditures, Adjusted revenues, Adjusted operating income, Adjusted net loss applicable to common stock, Cash operating margin and year-end pretax present worth of proved reserves discounted at 10% "PV-10". Management believes Adjusted EBITDAX, Discretionary cash flow, Adjusted revenues, Adjusted operating income, Adjusted net loss applicable to common stock and Cash operating margin are good financial indicators of the Company's ability to internally generate operating funds, while drilling and completion capital expenditures are a useful measure of the Company's annual drilling expenditures. Neither discretionary cash flow, nor Adjusted EBITDAX, should be considered an alternative to net cash provided by operating activities, as defined by GAAP. Adjusted revenues should not be considered an alternative to total revenues, as defined by GAAP. Adjusted operating income should not be considered an alternative to operating income (loss), as defined by GAAP. Adjusted net loss applicable to common stock should not be considered an alternative to net loss applicable to common stock, as defined by GAAP. Nor should drilling and completion capital expenditures be considered an alternative to costs incurred in oil and gas property acquisition, exploration, and development activities, as defined by GAAP. Management also believes that year-end PV-10 of proved reserves discounted at 10% is a helpful comparative indicator of proved reserves from company to company without regard to an individual company's tax position, as is taken into account in reducing PV-10 by the discounted amount of estimated future income tax expense, resulting in the GAAP-required standardized measure of discounted future net cash flows ("SMOG"). The company's discounted future income taxes are estimated to be $1.6 million at December 31, 2012 to arrive at a SMOG of $357.4 million. Management believes that all of these non-GAAP financial measures provide useful information to investors because they are monitored and used by Company management and widely used by professional research analysts in the valuation and investment recommendations of companies within the oil and gas exploration and production industry.

Initial production rates are subject to decline over time and should not be regarded as reflective of sustained production levels. In particular, production from horizontal drilling in shale oil and natural gas resource plays and tight natural gas plays that are stimulated with extensive pressure fracturing are typically characterized by significant early declines in production rates.

Unless otherwise stated, oil production volumes include condensate.

Certain statements in this news release regarding future expectations and plans for future activities may be regarded as "forward looking statements" within the meaning of the Securities Litigation Reform Act. They are subject to various risks, such as financial market conditions, changes in commodities prices and costs of drilling and completion, operating hazards, drilling risks, and the inherent uncertainties in interpreting engineering data relating to underground accumulations of oil and gas, as well as other risks discussed in detail in the Company's Annual Report on Form 10-K for the year ended December 31, 2012 and other subsequent filings with the Securities and Exchange Commission. Although the Company believes that the expectations reflected in such forward looking statements are reasonable, it can give no assurance that such expectations will prove to be correct.

Goodrich Petroleum is an independent oil and gas exploration and production company listed on the New York Stock Exchange.

Quantitative Reconciliation of Net Cash Drilling and Completion Capital Expenditures (non-GAAP) as used in the calculation of Organic Finding and Development Costs and Organic Proved Developed Finding and Development Costs to Net Cash Used in Investing Activities (GAAP):

Net Cash Used In Investing Activities (GAAP)	$161,494
Less: Cash Spent in 2012 for Expenditures Booked in 2011	(22,303)
Add: Proceeds from Sale of Assets	90,922
Net Capital Expenditures Booked in 2012 (non-GAAP)	$230,113
Less: Leasehold Acquisitions	(22,325)
Facilities & Infrastructure	(5,176)
Furniture, Fixtures & Equipment	(558)
Net Cash Drilling and Completions Capital Expenditures (non-GAAP)	$202,054

GOODRICH PETROLEUM CORPORATION
SELECTED INCOME AND PRODUCTION DATA
(In Thousands, Except Per Share Amounts)

	Three Months Ended December 31,		Year Ended December 31,	
	2012	2011	2012	2011
Volumes				
Natural gas (MMcf)	4,630	8,605	24,844	36,167
Oil and condensate (MBbls)	329	225	1,095	644
MMcfe - Total	6,603	9,956	31,415	40,029
Mcfe per day	71,774	108,220	85,832	109,669
Total Revenues	$ 48,231	$ 51,425	$ 180,845	$ 201,069
Operating Expenses				
Lease operating expense	4,671	5,925	25,938	21,490
Production and other taxes	2,363	1,256	8,115	5,450
Transportation and processing	2,840	5,492	13,900	12,974
Depreciation, depletion and amortization	37,084	38,577	141,222	131,811
Exploration	16,367	1,910	23,122	8,289
Impairment	45,156	6,919	47,818	8,111
General and administrative	7,177	7,970	28,930	29,799
Gain on sale of assets	(377)	-	(44,606)	(236)
Other	91	302	91	448
Operating loss	(67,141)	(16,926)	(63,685)	(17,067)
Other income (expense)				
Interest expense	(13,087)	(12,536)	(52,403)	(49,351)
Interest income and other	1	16	4	59
Gain on derivatives not designated as hedges	4,551	7,142	31,882	34,539
Gain on extinguishment of debt	-	-	-	62
	(8,535)	(5,378)	(20,517)	(14,691)
Loss before income taxes	(75,676)	(22,304)	(84,202)	(31,758)
Income tax benefit	-	-	-	-
Net loss	(75,676)	(22,304)	(84,202)	(31,758)
Preferred stock dividends	1,512	1,512	6,047	6,047
Net loss applicable to common stock	$ (77,188)	$ (23,816)	$ (90,249)	$ (37,805)
Unrealized (gain) loss on derivatives not designated as hedges	12,582	2,761	41,278	(3,234)
Other - litigation	91	302	91	448
Gain on sale of assets	(377)	-	(44,606)	(236)
Gain on extinguishment of debt	-	-	-	(62)
Dry hole costs	12,848	-	12,848	-
Impairment	45,156	6,919	47,818	8,111
Adjusted net loss applicable to common stock (1)	$ (6,888)	$ (13,834)	$ (32,820)	$ (32,778)

Discretionary cash flow (see non-GAAP reconciliation) (2)	$ 39,858	$ 34,755	$ 141,485	$ 133,838
Adjusted EBITDAX (see calculation and non-GAAP reconciliation) (3)	$ 50,505	$ 42,654	$ 184,025	$ 169,156
Weighted average common shares outstanding - basic	36,465	36,183	36,390	36,124
Weighted average common shares outstanding - diluted (4)	36,465	36,183	36,390	36,124
Earnings per share				
Net loss applicable to common stock - basic	$ (2.12)	$ (0.66)	$ (2.48)	$ (1.05)
Net loss applicable to common stock - diluted	$ (2.12)	$ (0.66)	$ (2.48)	$ (1.05)
Adjusted earnings per share				
Adjusted net loss applicable to common stock - basic (1)	$ (0.19)	$ (0.38)	$ (0.90)	$ (0.91)
Adjusted net loss applicable to common stock - fully diluted (1)	$ (0.19)	$ (0.38)	$ (0.90)	$ (0.91)

(1) Adjusted net income applicable to common stock is defined as net income (loss) applicable to common stock adjusted to exclude certain charges or amounts in order to provide users of this financial information with additional meaningful comparisons between current results and the results of prior periods. Management presents this measure because (i) it is consistent with the manner in which the company's performance is measured relative to the performance of its peers, (ii) this measure is more comparable to earnings estimates provided by securities analysts, and (iii) charges or amounts excluded cannot be reasonably estimated and guidance provided by the company excludes information regarding these types of items. These adjusted amounts are not a measure of financial performance under GAAP.

(2) Discretionary cash flow is defined as net cash provided by operating activities before changes in operating assets and liabilities. Management believes that the non-GAAP measure of operating cash flow is useful as an indicator of an oil and gas exploration and production company's ability to internally fund exploration and development activities and to service or incur additional debt. The company has also included this information because changes in operating assets and liabilities relate to the timing of cash receipts and disbursements which the company may not control and may not relate to the period in which the operating activities occurred. Operating cash flow should not be considered in isolation or as a substitute for net cash provided by operating activities prepared in accordance with GAAP.

(3) Adjusted EBITDAX is earnings before interest expense, income tax, DD&A, exploration expense and impairment of oil and gas properties. In calculating EBITDAX for this purpose, earnings include realized gains (losses) from derivatives but exclude unrealized gains (losses) from derivatives. Other excluded items include Interest income and other, Gain on sale of assets, Gain on extinguishment of debt and Other expense.

(4) Fully diluted shares excludes approximately 10.2 million and 10.1 million potentially dilutive instruments that were anti-dilutive due to the net income (loss) applicable to common stock for the three months and year ended December 31, 2012, respectively. We report our financial results in accordance with accounting principles generally accepted in the United States of America ("GAAP"). However, management believes certain non-GAAP performance measures may provide users of this financial information with additional meaningful comparisons between current results and the results of our peers and of prior periods.

GOODRICH PETROLEUM CORPORATION
Per Unit Sales Prices and Costs

	Three Months Ended December 31,		Year Ended December 31,	
	2012	2011	2012	2011
Average sales price per unit:				
Oil (per Bbl)				
Including realized gain on oil derivatives	$ 110.12	$ 99.42	$ 106.98	$ 96.23
Excluding realized gain on oil derivatives	$ 98.63	$ 94.47	$ 99.91	$ 91.34
Natural gas (per Mcf)				
Including realized gain on natural gas derivatives	$ 6.20	$ 4.54	$ 5.50	$ 4.70
Excluding realized gain on natural gas derivatives	$ 3.31	$ 3.52	$ 2.86	$ 3.92
Natural gas and oil (per Mcfe)				
Including realized gain on oil and natural gas derivatives	$ 9.83	$ 6.17	$ 8.08	$ 5.79
Excluding realized gain on oil and natural gas derivatives	$ 7.24	$ 5.18	$ 5.75	$ 5.01
Costs Per Mcfe				
Lease operating expense	$ 0.71	$ 0.60	$ 0.83	$ 0.54
Production and other taxes	$ 0.36	$ 0.13	$ 0.26	$ 0.14
Transportation and processing	$ 0.43	$ 0.55	$ 0.44	$ 0.32
Depreciation, depletion and amortization	$ 5.62	$ 3.87	$ 4.50	$ 3.29
Exploration	$ 2.48	$ 0.19	$ 0.74	$ 0.21
Impairment	$ 6.84	$ 0.69	$ 1.52	$ 0.20
General and administrative	$ 1.09	$ 0.80	$ 0.92	$ 0.74

Gain on sale of assets	$ (0.06)	$ -	$ (1.42)	$ (0.01)
Other	$ 0.01	$ 0.03	$ -	$ 0.01
	$ 17.47	$ 6.87	$ 7.78	$ 5.45

Note: Amounts on a per Mcfe basis may not total due to rounding.

GOODRICH PETROLEUM CORPORATION
Selected Cash Flow Data (In Thousands):

Reconciliation of Discretionary Cash Flow and Net Cash Provided by Operating Activities (unaudited)

	Three Months Ended December 31,		Year Ended December 31,	
	2012	2011	2012	2011
Net cash provided by operating activities (GAAP)	$ 76,216	$ 26,403	$ 173,789	$ 136,340
Net changes in working capital	(36,358)	8,352	(32,304)	(2,502)
Discretionary cash flow	$ 39,858	$ 34,755	$ 141,485	$ 133,838
Weighted average common shares outstanding - basic	36,465	36,183	36,390	36,124
Weighted average common shares outstanding - diluted (4)	36,465	36,183	36,390	36,124

Supplemental Balance Sheet Data

	As of	
	December 31, 2012	December 31, 2011
Cash and cash equivalents	$ 1,188	$ 3,347
Long-term debt	568,671	566,126

Reconciliation of Net income (loss) to Adjusted EBITDAX

	Three Months Ended December 31,		Year Ended December 31,	
	2012	2011	2012	2011
Net loss (GAAP)	$ (75,676)	$ (22,304)	$ (84,202)	$ (31,758)
Exploration expense	16,367	1,910	23,122	8,289
Depreciation, depletion and amortization	37,084	38,577	141,222	131,811
Impairment	45,156	6,919	47,818	8,111
Stock compensation expense	2,192	1,969	6,903	6,495
Interest expense	13,087	12,536	52,403	49,351
Unrealized (gain) loss on derivatives not designated as hedges	12,582	2,761	41,278	(3,234)
Other excluded items *	(287)	286	(44,519)	91
Adjusted EBITDAX	$ 50,505	$ 42,654	$ 184,025	$ 169,156

* Other excluded items include Interest income and other, Gain on sale of assets, Gain on extinguishment of debt, Income taxes and Other expense.

Other Information

	Three Months Ended December 31,		Year Ended December 31,	
	2012	2011	2012	2011
Interest expense - cash	$ 9,674	$ 9,862	$ 39,583	$ 35,000
Interest expense - noncash	3,413	2,674	12,820	14,351
Total Interest	13,087	12,536	52,403	49,351
Unrealized (gain) loss on derivatives not designated as hedges	12,582	2,761	41,278	(3,234)
Realized gain on derivatives not designated as hedges	(17,133)	(9,903)	(73,160)	(31,305)
Total gain on derivatives not designated as hedges	(4,551)	(7,142)	(31,882)	(34,539)
General and Administrative expense - cash	4,985	6,001	22,027	23,304
General and Administrative expense - noncash	2,192	1,969	6,903	6,495

Total General and Administrative expense	7,177	7,970	28,930	29,799

GOODRICH PETROLEUM CORPORATION
Selected Cash Flow Data continued (In Thousands):

Reconciliation of Adjusted Revenues and Total Revenues (unaudited)

	Three Months Ended December 31,		Year Ended December 31,	
	2012	2011	2012	2011
Total Revenues (GAAP)	$ 48,231	$ 51,425	$ 180,845	$ 201,069
Realized gain on derivatives not designated as hedges	17,133	9,903	73,160	31,305
Adjusted Revenues	$ 65,364	$ 61,328	$ 254,005	$ 232,374

Reconciliation of Adjusted Operating Income (Loss) and Operating Loss (unaudited)

	Three Months Ended December 31,		Year Ended December 31,	
	2012	2011	2012	2011
Operating loss (GAAP)	$ (67,141)	$ (16,926)	$ (63,685)	$ (17,067)
Realized gain on derivatives not designated as hedges	17,133	9,903	73,160	31,305
Adjusted Operating Income (Loss)	$ (50,008)	$ (7,023)	$ 9,475	$ 14,238

Calculation of Cash operating margin (unaudited)

	Three Months Ended December 31,		Year Ended December 31,	
	2012	2011	2012	2011
Adjusted EBITDAX (see calculation and non-GAAP reconciliation) (3)	$ 50,505	$ 42,654	$ 184,025	$ 169,156
Adjusted Revenues (see non-GAAP reconciliation)	$ 65,364	$ 61,328	$ 254,005	$ 232,374
Cash operating margin	77%	70%	72%	73%

SOURCE Goodrich Petroleum Corporation