Goodrich Petroleum Announces Second Quarter 2014 Financial Results And Operational Update

HOUSTON, Aug. 7, 2014 /PRNewswire/ -- Goodrich Petroleum Corporation (NYSE: GDP) (the "Company") today announced financial and operating results for the second quarter ended June 30, 2014.

FINANCIAL RESULTS:

- Revenues totaled $53.3 million in the quarter versus $48.5 million in the prior year period. Average realized price per unit was $8.53 per Mcfe in the quarter versus $7.22 per Mcfe in the prior year period;
- Earnings before interest, taxes, DD&A, non-cash general and administrative expenses and exploration ("Adjusted EBITDAX") totaled $31.5 million for the quarter and $60.5 million for the six month period ended June 30, compared to $31.5 million in the prior year quarter and $58.6 million in the prior year six month period;
- Oil production increased 30% to 381,000 barrels, or approximately 4,200 Bbls/day, during the quarter, compared to 292,000 barrels, or approximately 3,200 Bbls/day in the prior year period. Oil production grew 11% sequentially over the prior quarter.

TUSCALOOSA MARINE SHALE ("TMS"):

- The Company's SLC, Inc. 81H-1 (67% WI) well in West Feliciana Parish, Louisiana has achieved a peak 24-hour production rate to date of approximately 900 Boe/day (96% oil) from an approximate 7,000 foot lateral with 27 frac stages.
- The non-operated Lewis 7-18H-1 (17% WI) well in Amite County, Mississippi, has achieved a peak 24-hour production rate to date of approximately 1,500 Boe/day (93% oil) from an approximate 8,100 foot lateral with 29 frac stages.
- The non-operated Mathis 29-32H-1 well in Amite County, Mississippi has achieved a peak 24-hour production rate to date of approximately 1,300 Boe/day (92% oil) from an approximate 6,400 foot lateral with 17 frac stages. The Company owns a 6.5% reversionary interest in the well and the right to participate in subsequent wells drilled in the unit.
- The Company's previously announced Beech Grove 94H-1 (67% WI) well in East Feliciana Parish, Louisiana, which had a reported initial rate of 740 Boe/day, achieved a 30-day average production rate of approximately 600 Boe/day (90% oil). The Beech Grove continues to perform very well and has thus far exhibited a flatter decline curve profile. The well is currently producing approximately 550 Boe/day and is currently on the Company's 600 MBoe type curve.

FINANCIAL RESULTS

REVENUES

Revenues totaled $53.3 million in the quarter versus $48.5 million in the prior year period. Average realized price per unit was $8.53 per Mcfe in the quarter versus $7.22 per Mcfe in the prior year period. When factoring in the realized gain or loss on derivatives not designated as hedges, Adjusted Revenues totaled $50.2 million in the quarter versus $48.6 million in the prior year period, and average realized price per unit was $8.04 per Mcfe versus $7.23 per Mcfe in the prior year period.

(See accompanying tables at the end of this press release that reconciles Adjusted Revenues, a non-GAAP measure, to its most directly comparable GAAP financial measure.)

PRODUCTION

Production totaled 6.2 billion cubic feet equivalent ("Bcfe") in the quarter, or an average of 68,600 Mcfe/day, versus 6.7 Bcfe, or an average of 73,200 Mcfe/day in the prior year period. Oil production totaled 381,000 barrels of oil in the quarter, or an average of approximately 4,200 Bbls/day, versus 292,000 barrels of oil, or an average of approximately 3,200 Bbls/day, in the prior year period. Oil production grew 11% sequentially over the prior quarter. Oil production growth for the quarter was back-end loaded, with current production of approximately 4,800 – 5,000 Bbls/day and third quarter guidance of 4,800 – 5,400 Bbls/day. Natural gas production totaled 4.0 Bcf in the quarter, or an average of approximately 43,500 Mcf/day, versus 4.9 Bcf, or an average of 54,000 Mcf/day, in the prior year period. The Company anticipates producing 37,000 – 39,000 Mcf/day of natural gas during the third quarter of 2014.

CAPITAL EXPENDITURES

Capital expenditures totaled $106.5 million in the quarter, of which $89.9 million was spent on drilling and completion costs, $13.2 million on leasehold acquisition and $3.4 million on facilities, capital workovers and other expenditures. Approximately 70% of the quarter's total capital expenditures were spent in the TMS drilling and completing wells and extending existing leasehold for future drilling operations. Capital expenditures for the first six months of the year totaled $162.3 million, and the Company currently anticipates that its full year 2014 capital expenditure budget will be at the low end of the previously issued guidance range of $325 – $375 million.

CASH FLOW

Earnings before interest, taxes, DD&A, non-cash general and administrative expenses and exploration ("Adjusted EBITDAX") was $31.5 million in the quarter and the prior year period.

Discretionary cash flow ("DCF"), defined as net cash provided by operating activities before changes in working capital, was $18.4 million in the quarter, compared to $20.9 million in the prior year period. Net cash provided by operating activities was $63.3 million in the quarter, compared to $29.6 million in the prior year period.

DCF was impacted by non-recurring other operating expenses of $3.4 million comprised of $2.8 million for gathering and marketing costs on non-operated Haynesville Shale assets, which the Company is currently disputing, and a $0.6 million litigation charge pertaining to a long standing working interest dispute on a property the Company no longer owns. Adjusted EBITDAX and DCF were both impacted by a $3.1 million realized loss on derivatives not designated as hedges during the quarter compared to a $0.1 million realized gain on derivatives not designated as hedges during 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.)

<u>NET INCOME</u>

The Company announced a net loss applicable to common stock of $32.5 million in the quarter, or ($0.73) per basic share, versus a net loss applicable to common stock of $20.1 million, or ($0.55) per basic share in the prior year period. Adjusted net loss applicable to common stock was $21.3 million for the quarter, or ($0.48) per basic share, which excludes the impact of unrealized losses on derivatives not designated as hedges of $6.7 million, non-cash leasehold expiration of $1.1 million, and non-recurring other expenses of $3.4 million.

(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.)

<u>OPERATING EXPENSES</u>

Lease operating expense ("LOE") was $7.3 million in the quarter, or $1.17 per Mcfe, versus $5.9 million, or $0.88 per Mcfe, in the prior year period. LOE for the quarter included $1.4 million, or $0.22 per Mcfe, for workovers performed in the quarter, versus $1.1 million, or $0.17 per Mcfe, in the prior year period. The majority of the Company's workover expense pertained to cleanout operations on wells in the Eagle Ford and Haynesville Shale trends.

Production and other taxes were $2.0 million in the quarter, or $0.32 per Mcfe, versus $2.7 million, or $0.41 per Mcfe, in the prior year period. Production taxes continued to decrease in the quarter versus the prior year period due primarily to higher oil volumes from the TMS, where new wells are subject to no or very low production taxes until payout of the well is achieved.

Transportation and processing expense was $2.3 million in the quarter, or $0.37 per Mcfe, versus $2.5 million, or $0.37 per Mcfe, in the prior year period.

Depreciation, depletion and amortization ("DD&A") expense was $30.1 million in the quarter, or $4.82 per Mcfe, versus $34.5 million, or $5.18 per Mcfe, in the prior year period. The decline in DD&A expense per unit of production was driven primarily by higher year-end 2013 reserves and lower capital expenditures per well in the Eagle Ford Shale trend.

Exploration expense was $2.4 million in the quarter, or $0.38 per Mcfe, versus $9.5 million, or $1.43 per Mcfe, in the prior year period, which included non-cash expenses associated with expiration of non-core, undeveloped leasehold in the Eagle Ford Shale trend.

General and Administrative ("G&A") expense was $9.5 million in the quarter, or $1.51 per Mcfe, versus $7.6 million, or $1.15 per Mcfe, in the prior year period, primarily due to higher compensation expense and stock based compensation in the current quarter. G&A expense related to non-cash, stock based compensation totaled $2.3 million in the quarter, or $0.37 per Mcfe, versus $1.7 million, or $0.26 per Mcfe, in the prior year period.

<u>OPERATING INCOME</u>

Operating income, defined as revenues minus operating expenses, totaled a loss of $3.6 million in the quarter, versus an operating loss of $14.2 million in the prior year period. Adjusted operating loss, when adjusted for realized loss on derivatives not designated as hedges, was a loss of $6.6 million for the quarter.

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

<u>INTEREST EXPENSE</u>

Interest expense totaled $11.8 million in the quarter, or $1.88 per Mcfe, versus $13.0 million, or $1.96 per Mcfe, in the prior year period. Non-cash interest expense associated with the Company's debt totaled $2.7 million (representing 23% of total interest expense) in the quarter, or $0.43 per Mcfe, versus $3.4 million, or $0.51 per Mcfe, in the prior year period.

<u>CRUDE OIL AND NATURAL GAS DERIVATIVES</u>

The Company realized a loss of $3.1 million on its derivatives not designated as hedges and an unrealized loss of $6.7 million, which resulted in a net loss of $9.8 million on its derivatives not designated as hedges in the quarter, versus a net gain of $11.1 million during the prior year period.

For the remainder of 2014, the Company has a total of 3,800 Bbls/day swapped at a blended price of $93.65 per Bbl, which includes 2,500 Bbls/day swapped at a NYMEX crude oil price of $93.18 per Bbl and 1,300 Bbls/day swapped at a LLS crude oil price of $94.55 per Bbl. For 2015, the Company now has a total of 3,500 Bbls/day swapped at an average LLS price of $96.11 per Bbl. The Company will continue to add incremental oil hedges as production volumes increase in the TMS.

With regard to natural gas, the Company has 30,000 MMBtu/day swapped at an average NYMEX natural gas price of $4.76 per MMBtu for the remainder of 2014.

LIQUIDITY

The Company exited the quarter with $0.5 million in cash, $51.8 million of restricted cash and $48 million drawn on its senior credit facility. Currently, the Company's senior credit facility has a borrowing base of $250 million. The Company expects to finance the remainder of its 2014 capital expenditure budget with cash flow from operations and available capacity on its senior credit facility.

OPERATIONAL UPDATE

For the quarter, the Company conducted drilling operations on 15.0 gross (10.2 net) wells, of which 9.0 gross (5.8 net) were in the TMS, 5.0 gross (3.3 net) were in the Eagle Ford Shale trend, and 1.0 gross (1.0 net) in the Angelina River Trend / Shelby Trough area of the Haynesville Shale. A total of 7.0 gross (5.1 net) wells were added to production during the quarter, which included 4.0 gross (3.1 net) wells in the TMS and 3.0 gross (2.0 net) wells in the Eagle Ford Shale trend. As of June 30, 2014, the Company had 5.0 gross (2.3 net) wells drilled and waiting on completion, which was comprised of 3.0 gross (1.0 net) wells in the TMS and 2.0 gross (1.3 net) wells in the Eagle Ford Shale trend.

Tuscaloosa Marine Shale:

The Company's SLC, Inc. 81H-1 (67% WI) well in West Feliciana Parish, Louisiana has achieved a peak 24-hour production rate to date of approximately 900 Boe/day, comprised of 860 Bbls of oil and 240 Mcf of natural gas (96% oil) on a 12/64 inch choke from an approximate 7,000 foot lateral with 27 frac stages. The well is the Company's deepest well drilled to date in the TMS with an approximate true vertical depth of 14,000 feet.

The Company's previously announced Beech Grove 94H-1 (67% WI) well in East Feliciana Parish, Louisiana, which had a reported initial production rate of 740 Boe/day, achieved a 30-day average production rate of approximately 600 Boe/day (90% oil). The Beech Grove continues to perform very well and has thus far exhibited a flatter decline curve profile. The well is currently producing approximately 550 Boe/day and is currently on the Company's 600 MBoe type curve.

The Company participated in the non-operated Lewis 7-18H-1 (17% WI) well in Amite County, Mississippi, which achieved a peak 24-hour production rate to date of approximately 1,500 Boe/day, comprised of 1,400 Bbls of oil and 600 Mcf of natural gas on a 18/64 inch choke from an approximate 8,100 foot lateral with 29 frac stages.

The Company retains a reversionary interest in the non-operated Mathis 29-32H-1 well, which achieved a peak 24-hour production rate to date of approximately 1,300 Boe/day, comprised of 1,200 Bbls of oil and 600 Mcf of natural gas on a 18/64 inch choke from an approximate 6,400 foot lateral with 17 frac stages. The Company owns a 6.5% reversionary interest in the well and the right to participate in subsequent wells drilled in the unit.

In Amite County, Mississippi, the Company is currently drilling its Spears 31-6H-1 (77% WI) well, which is an offset to, and drilling off the same pad as, the Company's C.H. Lewis 30-19H-1 (81% WI) well. In Wilkinson County, Mississippi, the Company continues to conduct drilling operations on its CMR/Foster Creek 31-22H-1 (90% WI) and its CMR/Foster Creek 24-13H-1 (97% WI) wells, both of which are offsets to the Company's Crosby 12H-1 (50% WI) well.

The Company has commenced completion operations on its Denkmann 33-28H-2 (75% WI) well in Amite County, Mississippi. The well was drilled with an approximate 6,200 foot lateral and will be completed with 22 frac stages. Upon completion of the Denkmann well, the same frac crew will move to the Company's Bates 25-24H-1 (98% WI) well. Completion and frac operations on the CMR/Foster Creek 24-13H-1 (97% WI) and CMR/Foster Creek 31-22H #1 (90% WI) wells are expected to commence in late August to early September. The Company plans to announce completion results from all four wells during the third quarter.

The Company currently has in excess of 300,000 net acres in the TMS.

OTHER INFORMATION

In this press release, the Company refers to several non-GAAP financial measures, including Adjusted EBITDAX, DCF, Adjusted revenues, Adjusted operating income (loss), Adjusted net loss applicable to common stock and Cash operating margin. Management believes Adjusted EBITDAX, DCF, Adjusted revenues, Adjusted operating income (loss), 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. None of DCF, Adjusted EBITDAX or Cash operating margin, 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 (loss) 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. 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, 2013 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.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Volumes				
Natural gas (MMcf)	3,957	4,906	8,388	9,050
Oil and condensate (MBbls)	381	292	722	600
MMcfe - Total	6,245	6,658	12,721	12,651
Mcfe per day	68,623	73,167	70,281	69,893
Total Revenues	$ 53,319	$ 48,485	$ 105,122	$ 95,569
Operating Expenses				
Lease operating expense	7,312	5,881	15,929	13,097
Production and other taxes	1,983	2,742	4,424	5,502
Transportation and processing	2,339	2,476	4,711	5,073
Depreciation, depletion and amortization	30,076	34,513	59,314	69,487
Exploration	2,350	9,511	4,667	12,846
General and administrative	9,454	7,645	18,395	17,032
Gain on sale of assets	-	-	-	(43)
Other	3,357	(91)	3,357	(91)
Operating loss	(3,552)	(14,192)	(5,675)	(27,334)
Other income (expense)				
Interest expense	(11,751)	(13,027)	(23,629)	(26,400)
Interest income and other	10	15	20	19
Gain (loss) on derivatives not designated as hedges	(9,813)	11,061	(18,314)	9,109
	(21,554)	(1,951)	(41,923)	(17,272)
Loss before income taxes	(25,106)	(16,143)	(47,598)	(44,606)
Income tax benefit	-	-	-	-
Net loss	(25,106)	(16,143)	(47,598)	(44,606)
Preferred stock dividends	7,430	3,956	14,861	5,468
Net loss applicable to common stock	$ (32,536)	$ (20,099)	$ (62,459)	$ (50,074)
Unrealized (gain) loss on derivatives not designated as hedges	6,734	(10,978)	12,504	(8,874)
Exploration - Seismic	-	634	-	1,047
Lease expirations	1,142	7,461	2,373	8,899
Dry hole cost	-	52	44	252
Gain on sale of assets	-	-	-	(43)
Other	3,357	(91)	3,357	(91)
Adjusted net loss applicable to common stock (1)	$ (21,303)	$ (23,021)	$ (44,181)	$ (48,884)
Discretionary cash flow (see non-GAAP				

reconciliation) (2)	$ 18,384	$ 20,928	$ 37,783	$ 37,249
Adjusted EBITDAX (see calculation and non-GAAP reconciliation)(3)	$ 31,450	$ 31,524	$ 60,501	$ 58,574
Weighted average common shares outstanding - basic	44,308	36,701	44,290	36,692
Weighted average common shares outstanding - diluted (4)	44,308	36,701	44,290	36,692
Earnings per share				
Net loss applicable to common stock - basic	$ (0.73)	$ (0.55)	$ (1.41)	$ (1.36)
Net loss applicable to common stock - diluted	$ (0.73)	$ (0.55)	$ (1.41)	$ (1.36)
Adjusted earnings per share				
Adjusted net loss applicable to common stock - basic (1)	$ (0.48)	$ (0.63)	$ (1.00)	$ (1.33)
Adjusted net loss applicable to common stock - fully diluted (1)	$ (0.48)	$ (0.63)	$ (1.00)	$ (1.33)

(1) Adjusted net income (loss) 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 early extinguishment of debt and Other expense.

(4) Fully diluted shares excludes approximately 10.7 million and 10.5 million potentially dilutive instruments that were anti-dilutive due to the net loss applicable to common stock for the three and six months ended June 30, 2014, 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 June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Average sales price per unit:				
Oil (per Bbl)				
Including realized gain/(loss) on oil derivatives	$ 91.23	$ 101.91	$ 91.28	$ 104.79

Excluding realized gain/(loss) on oil derivatives	$ 100.48	$ 101.62	$ 99.44	$ 104.40
Natural gas (per Mcf)				
Including realized gain/(loss) on natural gas derivatives	$ 3.89	$ 3.75	$ 3.97	$ 3.59
Excluding realized gain/(loss) on natural gas derivatives	$ 3.78	$ 3.75	$ 3.97	$ 3.59
Natural gas and oil (per Mcfe)				
Including realized gain/(loss) on oil and natural gas derivatives	$ 8.04	$ 7.23	$ 7.80	$ 7.54
Excluding realized gain/(loss) on oil and natural gas derivatives	$ 8.53	$ 7.22	$ 8.26	$ 7.52
Costs Per Mcfe				
Lease operating expense	$ 1.17	$ 0.88	$ 1.25	$ 1.04
Production and other taxes	$ 0.32	$ 0.41	$ 0.35	$ 0.43
Transportation and processing	$ 0.37	$ 0.37	$ 0.37	$ 0.40
Depreciation, depletion and amortization	$ 4.82	$ 5.18	$ 4.66	$ 5.49
Exploration	$ 0.38	$ 1.43	$ 0.37	$ 1.02
General and administrative	$ 1.51	$ 1.15	$ 1.45	$ 1.35
Gain on sale of assets/other	$ 0.54	$ (0.01)	$ 0.26	$ (0.01)
	$ 9.11	$ 9.41	$ 8.71	$ 9.71

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 June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Net cash provided by operating activities (GAAP)	$ 63,291	$ 29,588	$ 69,846	$ 35,860
Net changes in working capital	(44,907)	(8,660)	(32,063)	1,389
Discretionary cash flow	$ 18,384	$ 20,928	$ 37,783	$ 37,249
Weighted average common shares outstanding - basic	44,308	36,701	44,290	36,692
Weighted average common shares outstanding - diluted (4)	44,308	36,701	44,290	36,692

Supplemental Balance Sheet Data

	As of	
	June 30, 2014	December 31, 2013
Cash and cash equivalents	$ 454	$ 49,220
Long-term debt	486,378	435,866

Reconciliation of Net income (loss) to Adjusted EBITDAX

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Net loss (GAAP)	$ (25,106)	$ (16,143)	$ (47,598)	$ (44,606)

Exploration expense	2,350	9,511	4,667	12,846
Depreciation, depletion and amortization	30,076	34,513	59,314	69,487
Stock compensation expense	2,298	1,700	4,648	3,474
Interest expense	11,751	13,027	23,629	26,400
Unrealized (gain) loss on derivatives not designated as hedges	6,734	(10,978)	12,504	(8,874)
Other excluded items *	3,347	(106)	3,337	(153)
Adjusted EBITDAX	$ 31,450	$ 31,524	$ 60,501	$ 58,574

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

Other Information

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Interest expense - cash	$ 9,084	$ 9,599	$ 18,330	$ 19,558
Interest expense - noncash	2,667	3,428	5,299	6,842
Total Interest	11,751	13,027	23,629	26,400
Unrealized (gain) loss on derivatives not designated as hedges	6,734	(10,978)	12,504	(8,874)
Realized (gain) loss on derivatives not designated as hedges	3,079	(83)	5,810	(235)
Total (gain) loss on derivatives not designated as hedges	9,813	(11,061)	18,314	(9,109)
General and Administrative expense - cash	7,156	5,945	13,747	13,558
General and Administrative expense - noncash	2,298	1,700	4,648	3,474
Total General and Administrative expense	9,454	7,645	18,395	17,032

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

Reconciliation of Adjusted Revenues and Total Revenues (unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Total Revenues (GAAP)	$ 53,319	$ 48,485	$ 105,122	$ 95,569
Realized gain (loss) on derivatives not designated as hedges	(3,079)	83	(5,810)	235
Adjusted Revenues	$ 50,240	$ 48,568	$ 99,312	$ 95,804

Reconciliation of Adjusted Operating Income and Operating Income (unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Operating loss (GAAP)	$ (3,552)	$ (14,192)	$ (5,675)	$ (27,334)
Realized gain (loss) on derivatives not designated as hedges	(3,079)	83	(5,810)	235
Adjusted Operating loss	$ (6,631)	$ (14,109)	$ (11,485)	$ (27,099)

Calculation of Cash operating margin (unaudited)

Three Months Ended Six Months Ended

	June 30,		June 30,	
	2014	2013	2014	2013
Adjusted EBITDAX (see calculation and non-GAAP reconciliation) (3)	$ 31,450	$ 31,524	$ 60,501	$ 58,574
Adjusted Revenues (see non-GAAP reconciliation)	$ 50,240	$ 48,568	$ 99,312	$ 95,804
Cash operating margin	63%	65%	61%	61%

SOURCE Goodrich Petroleum Corporation

For further information: Robert C. Turnham, Jr., President, or Jan L. Schott, Chief Financial Officer, or Daniel E. Jenkins, Director of Investor Relations, (713) 780-9494