February 29, 2012

Northern Oil and Gas, Inc. Announces Record 2011 Earnings, Substantial Reserve Increase and Closing of Syndicated Credit Facility

WAYZATA, Minn., Feb. 29, 2012 /PRNewswire/ -- Northern Oil and Gas, Inc. (NYSE/AMEX: NOG) ("Northern Oil") today announced 2011 fourth quarter and full year financial results and year-end proved reserves and provided an operational update.

2011 Highlights:

- Proved reserves increased 198% year-over-year to 46.8 million barrels of crude oil equivalent ("BOE")
- PV10% value of proved reserves increased 273% year-over-year to $1.1 billion
- 117% production growth compared to 2010 (21% sequential quarter-over-quarter production growth in fourth quarter)
- Total revenues of $149 million, representing a 235% year-over-year increase
- Grew Adjusted EBITDA 138% year-over-year to $112.3 million in 2011
- Net income increased to $40.6 million in 2011

Expanded Credit Facility

On February 28, 2012, Northern Oil completed a syndication of its senior secured revolving credit facility that increased its maximum facility size to $750 million and current borrowing base to $250 million. The applicable interest rate margin of the credit facility ranges from LIBOR plus 1.75% to LIBOR plus 2.75%, depending on the amount drawn at any given time. The credit facility is governed by a semi-annual borrowing base redetermination derived from Northern Oil's total proved crude oil and natural gas reserves.

Royal Bank of Canada serves as the "Administrative Agent" under the syndicated credit facility, with SunTrust Bank serving as the "Syndication Agent," and Bank of Montreal, KeyBank N.A. and U.S. Bank N.A. serving as "Co-Documentation Agents." RBC Capital Markets and SunTrust Robinson Humphrey served as "Joint Lead Arrangers." Participating banks in the credit facility include Capital One, N.A., Bank of Scotland plc, Bank of Oklahoma, BB&T Capital Markets, Cadence Bank N.A. and Macquarie Bank Limited.

Management Comment

Michael Reger, CEO, commented: "Operationally, our 2011 performance reflects another year of successfully executing our strategy of developing our acreage position and building a long-life reserve base. Our success enabled us to increase proved reserves by 31.1 million BOE in 2011, representing approximately a 1,700% replacement of our 2011 produced reserves. During 2011, production increased 117% to 1.9 million BOE as compared to 2010 production of 0.9 million BOE. Record 2011 production was driven by a 123% increase in net producing wells to 57.9 net wells at December 31, 2011. We are also pleased with the expansion and syndication of our credit facility. With our increased borrowing capacity, we are well positioned to continue our growth and expansion. We continue to be impressed by the extensions of the field and the infill drilling potential that is now clearly evident. We wish to thank all the operators with which we have participated for their innovation in this premier oil resource play."

Full Year 2011

The following tables summarize the full-year operating and financial results for 2011 as compared to 2010:

	Year Ended December 31,		
	2011	**2010**	**Change**
Net Production:			
Crude Oil (Bbl)	1,791,979	849,845	111%
Natural Gas and other liquids (Mcf)	800,207	234,411	241%
Barrel of Crude Oil Equivalent (BOE)	1,925,347	888,914	117%
Average Daily Production:			
Crude Oil (Bbl)	4,910	2,328	111%
Natural Gas and other liquids (Mcf)	2,192	642	241%
Barrel of Crude Oil Equivalent (BOE)	5,275	2,435	117%
Average Sales Prices:			
Crude Oil (per Bbl)	$ 86.01	$ 68.27	26%
Effect of crude oil hedges on average price (per Bbl)	(7.48)	(0.55)	(1260%)
Crude Oil net of hedging (per Bbl)	78.53	67.72	16%
Natural Gas and other liquids (per Mcf)	6.63	6.26	6%
Realized price per BOE(a)	75.85	66.39	14%
Average Production Costs (per BOE of production):			
Production Expenses	$ 6.77	$ 3.70	83%
Production Taxes	7.43	6.16	21%
General and Administrative	7.08	8.10	(13)%
General and Administrative-non-cash stock based compensation(b)	3.20	4.01	(20)%
Depletion, Depreciation, Amortization and Accretion	21.38	19.22	11%
Interest Expense	0.30	0.66	(54)%

(a) Realized prices include realized gains or losses on cash settlements for commodity derivatives.

(b) Costs associated with stock compensation and restricted stock amortization, which have been reflected in the categories associated with the direct personnel costs, which are combined with the cash amounts in Northern Oil's Form 10-K for the fiscal year ended December 31, 2011.

In 2011, crude oil, natural gas and natural gas liquids ("NGL") sales increased 168% from 2010, driven primarily by a 117% increase in production and partially aided by a 14% increase in realized prices taking into account the effect of settled derivatives. Production volumes increased in 2011 primarily due to the addition of 32.3 net wells during the year, and higher crude oil prices favorably impacted the realized price per BOE in 2011.

As a result of oil price derivative activities, Northern Oil incurred a net cash settlement loss of $13,407,878 in 2011, compared to a loss of $469,607 in 2010. As a result of forward oil price changes, mark-to-market derivative gains and losses resulted in non-cash gains of $3,072,229 in 2011 compared to a non-cash loss of $14,545,477 in 2010. Most of Northern Oil's derivatives are not designated for hedge accounting and are accounted for using the mark-to-market accounting method whereby gains and losses from changes in the fair value of derivative instruments are recognized immediately into earnings.

Production expenses were $13,043,633 in 2011, compared to $3,288,482 in 2010. Northern Oil experiences increases in aggregate operating expenses as it adds new wells and maintains production from existing properties. On a per unit basis, production expenses per BOE increased from $3.70 per barrel sold in 2010 to $6.77 in 2011. This year-over-year increase was primarily due to increased costs associated with higher amounts of water hauling and disposal costs, inclement weather during the first half of 2011 and workover expenses as wells are placed onto pumping units.

Northern Oil pays production taxes based on realized crude oil and natural gas sales. These costs were $14,300,720 in 2011, compared to $5,477,975 in 2010. Production taxes were 9.0% and 9.2% in 2011 and 2010, respectively. The 2011 average production tax rate was lower than the 2010 average due to well additions that qualified for reduced rates or tax exemptions during 2011.

General and administrative expense was $13,624,892 for 2011 compared to $7,204,442 for 2010. The 2011 increase of $6.4 million when compared to 2010 is due to higher salaries and benefits ($0.9 million), increased share based compensation expense ($2.6 million), higher legal and professional expenses ($1.3 million) and higher office and other administrative expenses due to the addition of employees ($1.6 million). As a result of Northern Oil's growth, the number of employees increased by 122% in 2011 as compared to 2010 to provide additional staffing in the legal, finance and land departments.

Depletion, depreciation, amortization and accretion ("DD&A") was $41,169,618 in 2011, compared to $17,082,913 in 2010. The increase in aggregate DD&A expense for 2011 compared to 2010 was driven by a 117% increase in production. Depletion expense, the largest component of DD&A, was $21.20 per BOE in 2011, compared to $18.99 per BOE in 2010. Additionally, depletion rates rose in 2011 due to an increase in future development cost estimates to reflect the changes in well completion methodologies (for example, more stages per well due to longer lateral extensions).

The provision for income taxes was $26,835,300 in 2011, compared to $4,419,000 in 2010. The effective tax rate in 2011 was 39.8%, compared to an effective tax rate of 39.0% in 2010. Due to higher pre-tax income levels, Northern Oil increased its federal statutory rate from 34% to 35% in 2011. The effective tax rate was different than the statutory rate of 35% primarily due to state tax rates of 3.6% and 4.6% in 2011 and 2010, respectively.

Net income was $40,611,492 in 2011, compared to $6,917,300 in 2010. The increase in net income was driven by higher production levels and higher average sales prices received in 2011 as compared to 2010. The increased production expense, production taxes, general and administrative expenses and depletion expenses in 2011 described above partially offset higher oil and gas revenues. Higher net income levels increased diluted net income per common share to $0.65 in 2011, compared to $0.14 in 2010.

Fourth Quarter 2011

The following tables summarize Northern Oil's fourth quarter operating and financial results for 2011 as compared to 2010:

	Quarter Ended December 31,		
	2011	2010	Change
Net Production:			
Crude Oil (Bbl)	588,922	323,173	82%
Natural Gas and other liquids (Mcf)	303,076	107,405	182%
Barrel of Crude Oil Equivalent (BOE)	639,435	341,074	87%
Average Daily Production:			
Crude Oil (Bbl)	6,401	3,513	82%
Natural Gas and other liquids (Mcf)	3,294	1,167	182%
Barrel of Crude Oil Equivalent (BOE)	6,950	3,707	87%
Average Sales Prices:			
Crude Oil (per Bbl)	$ 86.94	$ 72.03	21%
Effect of crude oil hedges on average price (per Bbl)	(4.61)	(4.25)	8%
Crude Oil net of hedging (per Bbl)	82.33	67.78	21%
Natural Gas and other liquids (per Mcf)	6.72	5.92	13%
Realized price per BOE(a)	79.01	66.09	20%
Average Production Costs (per BOE of production):			
Production Expenses	$ 7.04	$ 3.84	83%
Production Taxes	6.43	6.46	-%
General and Administrative	5.49	5.75	(5)%
General and Administrative-non-cash stock based compensation(b)	0.96	2.45	(61)%
Depletion, Depreciation, Amortization and Accretion	23.42	25.47	(8)%
Interest Expense	0.25	0.37	(33)%

(a) Realized prices include realized gains or losses on cash settlements for commodity derivatives.

(b) Costs associated with stock compensation and restricted stock amortization, which have been reflected in the categories associated with the direct personnel costs, which are combined with the cash amounts in Northern Oil's Form 10-K for the fiscal year ended December 31, 2011.

In the fourth quarter of 2011, crude oil, natural gas and NGL sales increased 123% compared to the fourth quarter of 2010, driven primarily by an 87% increase in production and partially aided by a 20% increase in realized prices taking into account the effect of settled derivatives. Production volumes increased in 2011 primarily due to the addition of 32.3 net wells during the year, and higher crude oil prices favorably impacted the realized price per BOE in 2011.

As a result of derivative activities, Northern Oil incurred a net cash settlement loss of $2,712,872 in the fourth quarter of 2011, compared to a loss of $1,372,553 in the fourth quarter of 2010. As a result of forward oil price changes, mark-to-market derivative gains and losses were non-cash losses of $23,602,774 in the fourth quarter of 2011 compared to non-cash losses of $11,356,283 in the fourth quarter of 2010. Most of Northern Oil's derivatives are accounted for using the mark-to-market accounting method whereby gains and losses from changes in the fair value of derivative instruments are recognized immediately into earnings.

Production expenses were $4,500,872 in the fourth quarter of 2011 compared to $1,309,956 in the fourth quarter of 2010. Northern Oil experiences increases in aggregate operating expenses as it adds new wells and maintains production from existing properties. On a per unit basis, production expenses per BOE increased from $3.84 per barrel sold in the fourth quarter of 2010 to $7.04 in the fourth quarter of 2011. This increase was primarily due to increased costs associated with higher amounts of water hauling and disposal costs and workover expenses as wells are placed on to pumping units.

Northern Oil pays production taxes based on realized oil and gas sales. These costs were $4,112,412 in the fourth quarter of 2011, compared to $2,203,224 in the fourth quarter of 2010. Production taxes were 7.7% in the fourth quarter of 2011 and 9.2% in the fourth quarter of 2010. The 2011 average production tax rate was lower than the 2010 average due to well additions that qualified for reduced rates/or tax exemptions during 2011.

General and administrative expense was $3,510,897 for the fourth quarter of 2011, compared to $1,961,860 for the fourth quarter of 2010. The fourth quarter of 2011 increase of $1.5 million when compared to the fourth quarter of 2010 is due to higher compensation expense ($0.4 million), higher legal and professional expenses ($0.5 million) and higher office and other administrative expenses due to the addition of employees ($0.6 million). As a result of Northern Oil's growth, the number of employees increased in the legal, finance and land departments.

DD&A was $14,972,645 in the fourth quarter of 2011, compared to $8,688,786 in the fourth quarter of 2010. The increase in aggregate DD&A expense for the fourth quarter of 2011, compared to the fourth quarter of 2010 was driven by an 87% increase in production. Depletion expense, the largest component of DD&A, was $23.23 per BOE in the fourth quarter of 2011, compared to $25.31 per BOE in the fourth quarter of 2010.

The provision for income taxes was $1,110,000 of expense in the fourth quarter of 2011, compared to $1,011,000 of benefit in the fourth quarter of 2010. The fourth quarter of 2011 reflects an increase in the tax provision rate to 35% and certain non-deductible expenses for federal income tax purposes.

Net loss was $1,380,788 in the fourth quarter of 2011, compared to net loss of $1,750,422 in the fourth quarter of 2010. The non-cash losses on mark-to-market of derivative instruments of $23,602,774 in the fourth quarter of 2011 and $11,356,283 in the fourth quarter of 2010 unfavorably impacted each quarter's results. Additionally, increased production expense, production taxes, general and administrative expenses and depletion expenses in each of the respective periods were partially offset by higher oil and gas sales as described above. Net loss per fully diluted share was $0.02 in the fourth quarter of 2011 and $0.03 in the fourth quarter of 2010.

Adjusted EBITDA

Northern Oil's Adjusted EBITDA for 2011 was $112.3 million, which represents a 138% increase over Adjusted EBITDA of $47.1 million for 2010. Northern Oil's Adjusted EBITDA for the fourth quarter of 2011 was $39.1 million, which represents a 114% increase over Adjusted EBITDA of $18.2 million for the fourth quarter of 2010.

Northern Oil defines Adjusted EBITDA as net income before (i) interest expense, (ii) income taxes, (iii) depreciation, depletion and amortization, (iv) accretion of discount on asset retirement obligations, (v) gain (loss) on mark-to-market of derivative instruments and (vii) non-cash expenses relating to share-based payments recognized under ASC Topic 718. Net income excluding unrealized mark-to-market hedging gains or losses and Adjusted EBITDA are non-GAAP measures. A reconciliation of these measures to their most directly comparable GAAP measure is included in the accompanying financial tables found later in this release. Management believes the use of these non-GAAP financial measures provides useful information to investors to gain an overall understanding of current financial performance. Specifically, management believes the non-GAAP results included herein provide useful information to both management and investors by excluding certain expenses and unrealized commodity gains and losses that management believes are not indicative of the Company's core operating results. In addition, these non-GAAP financial measures are used by management for budgeting and forecasting as well as subsequently measuring the Company's performance, and management believes it is providing investors with financial measures that most closely align to its internal measurement processes.

2011 Year-End Reserves

Northern Oil's estimated total proved reserves at December 31, 2011 were approximately 46.8 million barrels of oil equivalent (MMBoe), a 198% increase as compared to 15.7 MMBoe at December 31, 2010. Approximately 34% of Northern Oil's proved reserves at December 31, 2011 are categorized as either proved developed producing or proved developed non-producing, meaning behind pipe. Approximately 66% are classified as proved undeveloped.

Northern Oil's estimated future cash flows, discounted at an annual rate of 10 percent before giving effect to income taxes (commonly known as Pre-Tax PV10% value), for proved reserves at 2011 year-end was $1.1 billion, a 273% increase as compared to$295.5 million at 2010 year-end. Please see below for further information regarding the Pre-Tax PV10% value.

Proved Reserves Summary at December 31, 2011(1)

Reserve Category	Crude Oil (MBbls)	Natural Gas (MMcf)	2011 MBOE(2)	2010 MBOE(2)	% Change		2011 Pre-Tax PV10% ($MM)(3)
Proved Developed Producing	13,308	7,779	14,605	5,307	175	%	$ 534.5
Proved Developed Non-Producing	1,030	673	1,142	1,119	2	%	17.1
Proved Undeveloped	27,538	21,217	31,074	9,309	234	%	549.7
Total Proved	41,877	29,669	46,822	15,735	198	%	$ 1,101

(1) Northern Oil's reserves estimates are based on reports prepared by Ryder Scott Company, L.P., independent reserve engineers. Crude oil and natural gas reserve quantities and related discounted future net cash flows as of December 31, 2011 are estimated assuming a constant realized price of $90.17 per barrel of crude oil and a constant realized price of $6.18 per Mcf of natural gas, using a BTU factor of 1.5 to reflect liquids and condensates. Under SEC guidelines, these crude oil and natural gas prices were based on an unweighted arithmetic average of the applicable first-day-of-the-month price for each month from January 2011 to December 2011.

(2) Barrels of crude oil equivalent ("BOE") are computed based on a conversion ratio of one BOE for each barrel of crude oil and one BOE for every 6,000 cubic feet (i.e., 6 Mcf) of natural gas.

(3) Pre-tax PV10% value may be considered a non-GAAP financial measure as defined by the Securities and Exchange Commission and is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable standardized financial measure. Pre-tax PV10% value is computed on the same basis as the standardized measure of discounted future net cash flows but without deducting future income taxes. As of December 31, 2011, the Company's discounted future income taxes were $262.6 million and the standardized measure of after-tax discounted future net cash flows was $838.7 million. Management believes pre-tax PV10% value is a useful measure for investors for evaluating the relative monetary significance of the Company's crude oil and natural gas properties. Management further believes investors may utilize pre-tax PV10% value as a basis for comparison of the relative size and value of the Company's reserves to other companies because many factors that are unique to each individual company impact the amount of future income taxes to be paid. Management uses this measure when assessing the potential return on investment related to crude oil and natural gas properties and acquisitions. However, pre-tax PV10% value is not a substitute for the standardized measure of discounted future net cash flows. Pre-tax PV10% value and the standardized measure of discounted future net cash flows do not purport to present the fair value of the Company's crude oil and natural gas reserves.

The table above assumes prices and costs discounted using an annual discount rate of 10% without future escalation, without giving effect to non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization, or federal income taxes. The "Pre-tax PV10%" values of proved reserves presented in the foregoing tables may be considered a non-GAAP financial measure as defined by the SEC.

The following table reconciles the pre-tax PV10% value of Northern Oil's SEC Pricing Proved Reserves to the standardized measure of discounted future net cash flows.

SEC Pricing Proved Reserves

(in thousands)

Standardized Measure Reconciliation	
Pre-tax Present Value of estimated future net revenues (Pre-tax PV10%)	$ 1,101,333
Future income taxes, discounted at 10%	262,636
Standardized measure of discounted future net cash flows	$ 838,697

Uncertainties are inherent in estimating quantities of proved reserves, including many risk factors beyond Northern Oil's control. Reserve engineering is a subjective process of estimating subsurface accumulations of crude oil and natural gas that cannot be measured in an exact manner. As a result, estimates of proved reserves may vary depending upon the engineer valuing the reserves. Further, Northern Oil's actual realized price for crude oil and natural gas is not likely to average the pricing parameters used to calculate proved reserves. As such, the crude oil and natural gas quantities and the value of those commodities ultimately recovered from Northern Oil's properties will vary from reserve estimates.

Acreage and Drilling Update

As of December 31, 2011, Northern Oil controlled approximately 168,000 net acres targeting the Williston Basin Bakken and Three Forks plays. In 2011, Northern Oil acquired leasehold interests covering an aggregate of approximately 43,239 net mineral acres in its key prospect areas, for an average cost of $1,832 per net acre. These acquisitions consisted of an average of approximately 244 net mineral acres per transaction. In the fourth quarter of 2011, Northern Oil acquired leasehold interests covering an aggregate of approximately 12,651 net mineral acres in its key prospect areas at an average price of $1,851 per acre.

As of December 31, 2011, Northern Oil had approximately 82,395 net acres developed, held by production or held by operation, which represented approximately 49% of Northern Oil's total Bakken and Three Forks position. Northern Oil currently has approximately 17,700 net acres undeveloped with expirations in 2012. Of that acreage, approximately 10,000 net acres are currently either permitted to drill, drilling or can be extended at Northern Oil's option, which limits 2012 acreage expiration risk to less than 5% of Northern Oil's overall Williston Basin position.

In 2011 Northern Oil spud approximately 40 net wells, consistent with its prior forecasts, and added 32.3 net wells to production. Northern Oil added 14.9 net wells to production in the fourth quarter of 2011, representing a record quarter for net well completions.

Northern Oil participated in the first of several planned Three Forks "Lower Bench" test wells with Continental Resources. Northern Oil is optimistic about the potential of these new production horizons. The Charlotte 2-22H, located in McKenzie County, North Dakota, had a 1,396 BOE per day IP rate and produced approximately 45,000 BOE in the first three months of production, according to Continental Resources' February 23, 2012 earnings call.

Capital Expenditures

Northern Oil's total capital expenditures were approximately $414 million for the year ending December 31, 2011. Northern Oil expects to spend approximately $60 million to $80 million on acreage acquisitions during 2012 and approximately $325 million on drilling during 2012.

Derivative Activity

Northern Oil had the following oil price derivative contracts outstanding as of February 15, 2012:

Weighted Average Prices of Costless Collars ($/Bbl)

Type	Remaining Term	Floor	Ceiling	BOPD	Total Barrels
2012					
Costless Collar	10 Months (Mar-Dec)	$ 85.00	$ 95.25	368	112,738
Costless Collar	10 Months (Mar-Dec)	90.00	103.50	673	206,060
Costless Collar	10 Months (Mar-Dec)	90.00	106.50	681	208,361
Costless Collar	10 Months (Mar-Dec)	90.00	110.00	880	269,296
Costless Collar	10 Months (Mar-Dec)	95.00	107.00	982	300,630
Total 2012 Collars		$ 90.86	$ 105.78	3585	1,097,085
2013					
Costless Collar	12 Months (Jan-Dec)	$ 85.00	$ 98.00	2,084	760,794
Costless Collar	12 Months (Jan-Dec)	90.00	103.50	410	149,515
Costless Collar	12 Months (Jan-Dec)	90.00	106.50	383	139,791
Costless Collar	12 Months (Jan-Dec)	90.00	110.00	616	224,900
Costless Collar	12 Months (Jan-Dec)	95.00	107.00	499	182,269
Total 2013 Collars		$ 88.02	$ 102.36	3,993	1,457,269

Weighted Average Prices of Commodity Swaps ($/Bbl)

Type	Remaining Term	Swap Price	BOPD	Total Barrels
2012				
Commodity Swap	4 Months (Mar-Jun)	80.00	762	93,000
Commodity Swap	4 Months (Mar-Jun)	81.50	1,066	130,000
Commodity Swap	4 Months (Mar-Jun)	85.50	328	40,000
Commodity Swap	10 Months (Mar-Dec)	95.15	1,101	337,000
Commodity Swap	10 Months (Mar-Dec)	100.00	654	200,000
Total 2012 Swaps		$ 91.90		800,000

FOURTH QUARTER AND FULL-YEAR 2011 EARNINGS RELEASE TELECONFERENCE CALL

In conjunction with Northern Oil's release of its financial and operating results, investors, analysts and other interested parties are invited to listen to a conference call with management on Wednesday, February 29, 2012 at 9:00 a.m. Central Standard Time. Details for the conference call are as follows:

Dial-In Number: (888) 244-2521 (US/Canada) and (913) 312-1447 (International)

Conference ID: 6300458 - Northern Oil and Gas, Inc. Fourth Quarter and Full-Year 2011

Replay Dial-In Number: (888) 203-1112 (US/Canada) and (719) 457-0820 (International)

Replay Access Code: 6300458 - Replay will be available through March 14, 2012

ABOUT NORTHERN OIL AND GAS

Northern Oil and Gas, Inc. is an exploration and production company based in Wayzata, Minnesota. Northern Oil's core area of focus is the Williston Basin Bakken and Three Forks trend in North Dakota and Montana.

More information about Northern Oil and Gas, Inc. can be found at www.NorthernOil.com.

SAFE HARBOR

This press release contains forward-looking statements regarding future events and future results that are subject to the safe harbors created under the Securities Act of 1933 (the "Securities Act") and the Securities Exchange Act of 1934 (the "Exchange Act"). All statements other than statements of historical facts included in this report regarding the Company's financial position, business strategy, plans and objectives of management for future operations, industry conditions, and indebtedness covenant compliance are forward-looking statements. When used in this report, forward-looking statements are generally accompanied by terms or phrases such as "estimate," "project," "predict," "believe," "expect," "anticipate," "target," "plan," "intend," "seek," "goal," "will," "should," "may" or other words and similar expressions that convey the uncertainty of future events or outcomes. Items contemplating or making assumptions about, actual or potential future sales, market size, collaborations, and trends or operating results also constitute such forward-looking statements.

Forward-looking statements involve inherent risks and uncertainties, and important factors (many of which are beyond the Company's control) that could cause actual results to differ materially from those set forth in the forward-looking statements, including the following, changes in crude oil and natural gas prices, general economic or industry conditions, nationally and/or in the communities in which the Company conducts business, changes in the interest rate environment, legislation or regulatory requirements, conditions of the securities markets, the Company's ability to raise capital, changes in accounting principles, policies or guidelines, financial or political instability, acts of war or terrorism, and other economic, competitive, governmental, regulatory and technical factors affecting the Company's operations, products, services and prices.

The Company has based these forward-looking statements on its current expectations and assumptions about future events. While management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond the Company's control.

CONTACT:

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NORTHERN OIL AND GAS, INC.
STATEMENTS OF INCOME

	Three Months Ended December 31, (Unaudited)		Year Ended December 31,	
	2011	2010	2011	2010
REVENUES				
Oil and Gas Sales	$ 53,235,604	$ 23,913,044	$ 159,439,508	$ 59,488,284
Loss on Settled Derivatives	(2,712,872)	(1,372,553)	(13,407,878)	(469,607)
(Loss) Gain on Mark-to-Market of Derivative Instruments	(23,602,774)	(11,356,283)	3,072,229	(14,545,477)
Other Revenue	66,250	37,784	285,234	85,900
	26,986,208	11,221,992	149,389,093	44,559,100
OPERATING EXPENSES				
Production Expenses	4,500,872	1,309,956	13,043,633	3,288,482
Production Taxes	4,112,412	2,203,224	14,300,720	5,477,975
General and Administrative Expense	3,510,897	1,961,860	13,624,892	7,204,442
Depletion of Oil and Natural Gas Properties	14,852,963	8,632,410	40,815,426	16,884,563
Depreciation and Amortization	83,932	65,398	298,137	176,595
Accretion of Discount on Asset Retirement Obligations	35,750	(9,022)	56,055	21,755
Total Expenses	27,096,826	14,163,826	82,138,863	33,053,812
INCOME (LOSS) FROM OPERATIONS	(110,618)	(2,941,834)	67,250,230	11,505,288
OTHER INCOME (EXPENSE)				
Interest Expense	(160,295)	(127,672)	(585,982)	(583,376)
Interest Income	125	169,052	567,452	472,912
Gain (Loss) on Available for Sale Securities	-	139,032	215,092	(58,524)
Total Other Income (Expense)	(160,170)	180,412	196,562	(168,988)
INCOME (LOSS) BEFORE INCOME TAXES	(270,788)	(2,761,422)	67,446,792	11,336,300
INCOME TAX PROVISION (BENEFIT)	1,110,000	(1,011,000)	26,835,300	4,419,000
NET INCOME (LOSS)	$ (1,380,788)	$ (1,750,422)	$ 40,611,492	$ 6,917,300
Net Income (Loss) Per Common Share - Basic	$ (0.02)	$ (0.03)	$ 0.66	$ 0.14
Net Income (Loss) Per Common Share - Diluted	$ (0.02)	$ (0.03)	$ 0.65	$ 0.14
Weighted Average Shares Outstanding – Basic	62,028,912	55,854,487	61,789,289	50,387,203

Weighted Average Shares Outstanding - Diluted	62,028,912	55,854,487	62,195,340	50,778,245

NORTHERN OIL AND GAS, INC.
BALANCE SHEETS

	December 31, 2011	December 31, 2010
CURRENT ASSETS		
Cash and Cash Equivalents	$ 6,279,587	$ 152,110,701
Trade Receivables	51,418,830	22,033,647
Advances to Operators	17,530,474	13,225,650
Prepaid Expenses	486,421	345,695
Other Current Assets	317,460	475,967
Short - Term Investments	-	39,726,700
Deferred Tax Asset	4,472,000	5,100,000
Total Current Assets	80,504,772	233,018,360
PROPERTY AND EQUIPMENT		
Oil and Natural Gas Properties, Full Cost Method of Accounting		
Proved	566,195,321	158,846,475
Unproved	137,784,903	136,135,163
Other Property and Equipment	2,988,641	2,479,199
Total Property and Equipment	706,968,865	297,460,837
Less - Accumulated Depreciation and Depletion	63,265,919	22,152,356
Total Property and Equipment, Net	643,702,946	275,308,481
DEBT ISSUANCE COSTS	1,386,201	1,367,124
TOTAL ASSETS	$ 725,593,919	$ 509,693,965

LIABILITIES AND STOCKHOLDERS' EQUITY

	December 31, 2011	December 31, 2010
CURRENT LIABILITIES		
Accounts Payable	$ 110,133,286	$ 48,500,204
Accrued Expenses	131,012	2,829
Derivative Liability	9,363,068	11,145,319
Other Liabilities	33,229	18,574
Total Current Liabilities	119,660,595	59,666,926
LONG-TERM LIABILITIES		
Revolving Credit Facility	69,900,000	-
Derivative Liability	2,574,903	5,022,657
Other Noncurrent Liabilities	959,366	477,900
Deferred Tax Liability	35,929,000	9,167,000
Total Long-Term Liabilities	109,363,269	14,667,557

Total Liabilities	229,023,864	74,334,483
STOCKHOLDERS' EQUITY		
Preferred Stock, Par Value $.001; 5,000,000 Authorized,		
No Shares Outstanding	-	-
Common Stock, Par Value $.001; 95,000,000 Authorized,		
(12/31/2011 - 63,330,421 Shares Outstanding and 12/31/2010 –		
62,129,424 Shares Outstanding)	63,330	62,129
Additional Paid-In Capital	448,198,350	428,484,092
Retained Earnings	48,370,684	7,759,192
Accumulated Other Comprehensive Loss	(62,309)	(945,931)
Total Stockholders' Equity	496,570,055	435,359,482
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 725,593,919	$ 509,693,965

NORTHERN OIL AND GAS, INC.
Reconciliation of Adjusted EBITDA
(UNAUDITED)

	Three Months Ended December 31,		Year Ended December 31,	
	2011	**2010**	**2011**	**2010**
Net Income (Loss)	$ (1,380,788)	$ (1,750,422)	$ 40,611,492	$ 6,917,300
Add Back:				
Income Tax Provision (Benefit)	1,110,000	(1,011,000)	26,835,300	4,419,000
Depreciation, Depletion, Amortization and Accretion	14,972,645	8,688,785	41,169,618	17,082,913
Share Based Compensation	612,079	835,354	6,164,324	3,566,133
Loss (Gain) on Mark-to-Market of Derivative Instruments	23,602,774	11,356,283	(3,072,229)	14,545,477
Interest Expense	160,295	127,672	585,982	583,376
Adjusted EBITDA	$ 39,077,005	$ 18,246,672	$ 112,294,487	$ 47,114,199

NORTHERN OIL AND GAS, INC.
Reconciliation of GAAP Net Income to Non-GAAP Net Income Excluding
Unrealized Mark-to Market Derivative Gains and Losses
(UNAUDITED)

	Three Months Ended December 31		Year Ended December 31	
	2011	**2010**	**2011**	**2010**
Net Income (Loss)	$ (1,380,788)	$ (1,750,422)	$ 40,611,492	$ 6,917,300

Loss (Gain) on Mark-to-Market of Derivative Instruments	23,602,774	11,356,283	(3,072,229)	14,545,477
Tax Impact	(8,948,000)	(4,429,000)	1,223,000	(5,649,000)
Net Income without the Effect of Certain Items	$ 13,273,986	$ 5,176,861	$ 38,762,263	$15,813,777
Net Income Per Common Share - Basic	$ 0.21	$ 0.09	$ 0.63	$ 0.31
Net Income Per Common Share - Diluted	$ 0.21	$ 0.09	$ 0.62	$ 0.31
Weighted Average Shares Outstanding – Basic	62,028,912	55,854,487	61,789,289	50,387,203
Weighted Average Shares Outstanding - Diluted	62,436,366	56,287,837	62,195,340	50,778,245
Net Income (Loss) Per Common Share - Basic	$ (0.02)	$ (0.03)	$ 0.66	$ 0.14
Change due to Mark-to-Market of Derivative Instruments	0.38	0.20	(0.05)	0.28
Change due to Tax Impact	(0.15)	(0.08)	0.02	(0.11)
Net Income without Effect of Certain Items Per Common Share - Basic	$ 0.21	$ 0.09	$ 0.63	$ 0.31
Net Income (Loss) Per Common Share - Diluted	$ (0.02)	$ (0.03)	$ 0.65	$ 0.14
Change due to Mark-to-Market of Derivative Instruments	0.38	0.20	(0.05)	0.28
Change due to Tax Impact	(0.15)	(0.08)	0.02	(0.11)
Net Income without Effect of Certain Items Per Common Share - Diluted	$ 0.21	$ 0.09	$ 0.62	$ 0.31

SOURCE Northern Oil and Gas, Inc.