February 28, 2013

Northern Oil and Gas, Inc. Announces 2012 Fourth Quarter and Full Year Results

WAYZATA, Minn., Feb. 28, 2013 /PRNewswire/ -- Northern Oil and Gas, Inc. (NYSE MKT: NOG) today announced fourth quarter and full year results, year-end proved reserves, and 2013 production and capital budget guidance.

2012 HIGHLIGHTS

- Annual production increased 95% over 2011 to 3,760,123 barrels of oil equivalent ("Boe"), or 10,274 average Boe per day
- Total revenues, including the effects of derivatives, increased 109% over 2011 to $311.6 million
- Net income increased 78% over 2011 to $72.3 million
- Adjusted EBITDA increased 101% over 2011 to $225.3 million
- Proved reserves increased 44% over 2011 to 67.6 million barrels of oil equivalent
- Added 563 gross (48.3 net) wells to production bringing total producing wells to 1,227 gross (106.2 net)

MANAGEMENT COMMENT

Michael Reger, chairman and chief executive officer, commented: "2012 was a year of operational transition in the Williston Basin. Throughout the year, drilling costs peaked and abated, wellhead price differentials peaked and subsequently improved to some of the play's best levels and operators began the transition to pad drilling. As the play evolved, Northern responded with a strategic capital efficiency effort that resulted in an enhanced liquidity position. Combined with a strong hedge position, our liquidity should allow us to fund our 2013 capital expenditure requirements."

RESULTS OF OPERATIONS FOR 2012

The following table summarizes the full year operating and financial results for 2012 as compared to 2011:

	Year Ended December 31,		
	2012	2011	Change
Net Production:			
Oil (Bbl)	3,465,311	1,791,979	93%
Natural Gas and other liquids (Mcf)	1,768,872	800,207	121%
Total (Boe)	3,760,123	1,925,347	95%
Average Daily Production:			
Oil (Bbl)	9,468	4,910	93%
Natural Gas and other liquids (Mcf)	4,833	2,192	120%
Total (Boe)	10,274	5,275	95%

Average Sales Prices:			
Oil (per Bbl)	$ 83.22	$ 86.01	(3)%
Effect of oil hedges on average price (per Bbl)	(0.11)	(7.48)	98%
Oil net of hedging (per Bbl)	83.11	78.53	6%
Natural Gas and other liquids (per Mcf)	4.67	6.63	(30)%
Realized price per Boe [a]	78.79	75.85	4%
Average Production Costs (per Boe of production):			
Production Expenses	$ 8.61	$ 6.77	27%
Production Taxes	7.58	7.43	2%
General and Administrative	6.02	7.08	(15)%
Depletion, Depreciation, Amortization and Accretion	26.31	21.38	23%

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

In 2012, oil, natural gas and natural gas liquids ("NGL") sales, including the effect of settled derivatives, increased 103% from 2011, driven primarily by a 95% increase in production due to the addition of 48.3 net wells during the year. Northern's average oil price differential to the NYMEX WTI benchmark during 2012 was $9.79 per barrel, as compared to $6.30 per barrel in 2011.

As a result of oil price derivative activities, Northern incurred a net cash settlement loss of $0.4 million in 2012, compared to a loss of $13.4 million in 2011. As a result of forward oil price changes, mark-to-market derivative gains and losses resulted in a non-cash gain of $15.1 million in 2012 compared to a non-cash gain of $3.1 million in 2011.

Production expenses were $32.4 million in 2012, compared to $13.0 million in 2011. Northern experiences an increase in aggregate operating expenses as it adds new wells and maintains production from existing properties. On a per unit basis, the average production expenses per Boe increased from $6.77 per barrel sold in 2011 to $8.61 in 2012. The year-over-year increase on a per unit basis is primarily due to increased costs associated with water hauling, water disposal and servicing expenses. Production expenses are generally higher during a well's first year of operations, due to higher levels of servicing activities.

Northern pays production taxes based on realized oil and natural gas sales. These costs were $28.5 million in 2012, compared to $14.3 million in 2011. Average production tax rates were 9.6% and 9.0% in 2012 and 2011, respectively. The 2012 average production tax rate was higher than the 2011 average due to fewer wells that qualified for reduced rates or tax exemptions during 2012.

General and administrative expense was $22.6 million for 2012 compared to $13.6 million for 2011. The 2012 increase of $9.0 million when compared to 2011 is due to a $5.5 million severance charge in connection with the departures of the Company's former president and former chief operating officer, as well as higher personnel costs incurred as Northern continued to invest in its technical and operational staff to support its growth.

Depletion, depreciation, amortization and accretion ("DD&A") was $98.9 million in 2012, compared to $41.2 million in 2011. The increase in aggregate DD&A expense for 2012 compared to 2011 was driven by a 95% increase in production and higher depletion rates. Depletion expense, the largest component of DD&A, averaged $26.18 per Boe in 2012, compared to $21.20 per Boe in 2011. Depletion rates rose in 2012 due to increased future development cost and production expense estimates.

The provision for income taxes was $43.0 million in 2012, compared to $26.8 million in 2011. The effective tax rate in 2012 was 37.3%, compared to an effective tax rate of 39.8% in 2011. The decrease in the 2012 effective tax rate in 2012 as compared to 2011 was due to lower state tax levels.

Net income was $72.3 million in 2012, compared to $40.6 million in 2011. The increase in net income was driven by higher production levels in 2012 as compared to 2011. The increased production expense, interest expense, and depletion expenses in 2012 partially offset higher oil and gas revenues. Diluted net income per common share increased to $1.15 in 2012, compared to $0.65 in 2011.

Adjusted Net Income for 2012 was $66.2 million, or $1.05 per diluted share, as compared to $38.8 million, or $0.62 per diluted share, for 2011. The increase in Adjusted Net Income was primarily due to Northern's continued addition of oil and natural gas production from new wells, which was partially offset by a higher depletion rate in 2012 compared to 2011. Northern defines Adjusted Net Income as net income (loss) excluding (i) unrealized gain (loss) on derivative instruments, net of tax, and (ii) severance expenses in connection with the departures of Northern's former president and former chief operating officer, net of tax.

Adjusted EBITDA for 2012 was $225.3 million, which represents a 101% increase over Adjusted EBITDA of $112.3 million for 2011. Northern defines Adjusted EBITDA as net income (loss) before (i) interest expense, (ii) income taxes, (iii) depreciation, depletion, amortization and accretion, (iv) unrealized gain (loss) on derivative instruments and (v) non-cash share based compensation expense.

Adjusted Net Income 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 derivatives gains and losses that management believes are not indicative of Northern's core operating results. In addition, these non-GAAP financial measures are used by management for budgeting and forecasting as well as subsequently measuring Northern's performance, and management believes it is providing investors with financial measures that most closely align to its internal measurement processes.

FOURTH QUARTER 2012

The following tables summarize Northern's fourth quarter operating and financial results for 2012 as compared to 2011:

	Quarter Ended December 31,		
	2012	2011	Change
Net Production:			
Oil (Bbl)	909,317	588,922	54%
Natural Gas and other liquids (Mcf)	541,659	303,076	79%
Total (Boe)	999,593	639,435	56%

Average Daily Production:			
Oil (Bbl)	9,884	6,401	54%
Natural Gas and other liquids (Mcf)	5,888	3,294	79%
Total (Boe)	10,865	6,950	56%
Average Sales Prices:			
	$	$	
Oil (per Bbl)	85.86	86.94	(1)%
Effect of oil hedges on average price (per Bbl)	4.77	(4.61)	204%
Oil net of hedging (per Bbl)	90.63	82.33	10%
Natural Gas and other liquids (per Mcf)	4.23	6.72	(37)%
Realized price per Boe [(a)]	84.74	79.01	7%
Average Production Costs (per Boe of production):			
Production Expenses	$ 9.85	$ 7.04	40%
Production Taxes	7.66	6.43	19%
General and Administrative	4.08	5.49	(26)%
Depletion, Depreciation, Amortization and Accretion	26.79	23.42	14%

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

In the fourth quarter of 2012, oil, natural gas and NGL sales including the effect of settled derivatives, increased 68% compared to the fourth quarter of 2011, driven primarily by a 56% increase in production due to net wells added during the year. Northern's oil price differential to the NYMEX WTI benchmark during the fourth quarter of 2012 was $2.17 per barrel, as compared to $5.01 per barrel in the fourth quarter of 2011.

As a result of derivative activities, Northern incurred a net cash settlement gain of $4.3 million in the fourth quarter of 2012, compared to a loss of $2.7 million in the fourth quarter of 2011. As a result of forward oil price changes, mark-to-market derivative gains and losses were non-cash losses of $3.0 million in the fourth quarter of 2012 compared to non-cash losses of $23.6 million in the fourth quarter of 2011.

Production expenses were $9.8 million in the fourth quarter of 2012 compared to $4.5 million in the fourth quarter of 2011. Northern experiences an increase 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 $7.04 per barrel sold in the fourth quarter of 2011 to $9.85 in the fourth quarter of 2012. The increased cost on a per unit basis is primarily due to increased costs associated with water hauling, water disposal and servicing expenses. Production expenses are generally higher during a well's first year of operations, due to higher levels of servicing activities.

Northern pays production taxes based on realized oil and gas sales. These costs were $7.7 million in the fourth quarter of 2012, compared to $4.1 million in the fourth quarter of 2011. Average production tax rates were 9.5% in the fourth quarter of 2012 and 7.7% in the fourth quarter of 2011. The 2012 average production tax rate was higher than the 2011 average due to fewer wells that qualified for reduced rates or tax exemptions during 2012.

General and administrative expense was $4.1 million for the fourth quarter of 2012, compared to $3.5 million for the fourth quarter of 2011. The fourth quarter of 2012 increase was primarily driven by severance charges in connection with the departure of the Company's former chief operating officer.

DD&A was $26.8 million in the fourth quarter of 2012, compared to $15.0 million in the fourth quarter of 2011. The increase in aggregate DD&A expense for the fourth quarter of 2012 compared to the fourth quarter of 2011 was driven by a 56% increase in production and higher depletion rates. Depletion expense, the largest component of DD&A, was $26.66 per BOE in the fourth quarter of 2012, compared to $23.23 per BOE in the fourth quarter of 2011. Depletion rates rose in 2012 due to increased future development cost and higher production expense estimates.

The provision for income taxes was $8.1 million of expense in the fourth quarter of 2012, compared to $1.1 million in the fourth quarter of 2011. The increase in income tax expense in 2012 as compared to 2011 was due to higher levels of pretax income in 2012.

Net income was $19.6 million in the fourth quarter of 2012, compared to a loss of $1.4 million in the fourth quarter of 2011. Diluted net income per common share increased to $0.31 in the fourth quarter of 2012, compared to a loss of $0.02 in the fourth quarter of 2011.

Adjusted Net Income for the fourth quarter of 2012 was $21.4 million, or $0.34 per diluted share, as compared to $13.3 million, or $0.21 per diluted share, for the fourth quarter of 2011. Northern defines Adjusted Net Income as net income (loss) excluding (i) unrealized gain (loss) on derivative instruments, net of tax, and (ii) severance expenses in connection with the departures of Northern's former president and former chief operating officer, net of tax.

Northern's Adjusted EBITDA for the fourth quarter of 2012 was $64.3 million, which represents a 64% increase over Adjusted EBITDA of $39.1 million for the fourth quarter of 2011. Northern defines Adjusted EBITDA as net income (loss) before (i) interest expense, (ii) income taxes, (iii) depreciation, depletion, amortization and accretion, (iv) unrealized gain (loss) on derivative instruments and (v) non-cash share based compensation expense.

Adjusted Net Income and Adjusted EBITDA are non-GAAP measures. A reconciliation of these measures to the most directly comparable GAAP measure is included in the accompanying financial tables found later in this release.

ACREAGE AND DRILLING UPDATE

As of December 31, 2012, Northern controlled approximately 179,131 net acres targeting the Williston Basin Bakken and Three Forks. In 2012, Northern acquired leasehold interests covering an aggregate of approximately 17,590 net mineral acres in its key prospect areas, for an average cost of $1,788 per net acre, and earned an additional 6,450 net acres through farm-in arrangements. In the fourth quarter of 2012, Northern acquired leasehold interests covering an aggregate of approximately 3,404 net mineral acres in its key prospect areas at an average price of $1,082 per acre.

As of December 31, 2012, approximately 64% of Northern's total acreage position, and approximately 72% of Northern's North Dakota acreage position, was developed, held by production, held by operations or permitted.

In 2012 Northern spud approximately 42.8 net wells and added 48.3 net wells to production. Northern added 7.7 net wells to production in the fourth quarter of 2012.

CAPITAL EXPENDITURES

During 2012, Northern's acquisition and development expenditures included approximately $485 million of drilling, completion and capitalized workover costs, $8.5 million of capitalized internal costs and $5.9 million of capitalized interest. Northern's drilling and completion expenditures were heavily weighted to the first half of 2012, as operators worked through the backlog of wells awaiting completion at the end of 2011. Also in 2012, approximately $37 million was expended on acreage acquisitions and other acreage related costs located in the Williston Basin.

LIQUIDITY UPDATE

Northern ended the year with $124 million drawn on its revolving credit facility, which has a total borrowing capacity of $350 million. Northern also ended the year with $13 million in cash, resulting in liquidity of approximately $240 million.

CAPITAL PROGRAM AND PRODUCTION GUIDANCE FOR 2013

Northern expects 2013 total capital expenditures to range between $420 and $440 million. The total capital budget includes:

- $370 to $390 million in drilling and completions expense
- $20 million on acreage acquisitions
- Approximately $30 million of other capital expenditure activities, primarily capitalized workover expenses.

The 2013 budget anticipates the Company will participate in the drilling and completion of approximately 44 net wells targeting the Bakken and Three Forks formations during 2013. Northern expects the average well cost to range between $8.4 to $8.8 million per well. Northern expects cash flow from operations and its revolving credit facility to meet its capital expenditure needs for 2013.

Based on the assumed net well additions outlined above, Northern estimates 2013 production to be in a range of 4.7 to 5.0 million barrels of oil equivalent. Based on current activity and production levels, Northern estimates that production growth and the benefits from developmental multi-well pad drilling will be weighted towards the second half of 2013.

2012 YEAR-END RESERVES

Based on reports prepared by Ryder Scott Company, L.P., Northern's estimated total proved reserves at December 31, 2012 were approximately 67.6 million barrels of oil equivalent (MMBoe), a 44% increase as compared to 46.8 MMBoe at December 31, 2011. Approximately 45% of Northern's proved reserves at December 31, 2012 are categorized as either proved developed producing or proved developed non-producing, meaning behind pipe. Approximately 55% are classified as proved undeveloped.

Additional information regarding Northern's proved reserves, including 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), is attached at the end of this release.

FOURTH QUARTER AND FULL-YEAR 2012 EARNINGS RELEASE TELECONFERENCE CALL

In conjunction with Northern'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 Friday, March 1, 2013 at 9:00 a.m. Central Standard Time. Details for the conference call are as follows:

> Dial-In Number: (888) 481-2845 (US/Canada) and (719) 457-2635 (International)
> Conference ID: 1154820 - Northern Oil and Gas, Inc. Fourth Quarter and Full-Year 2012 Earnings Call
> Replay Dial-In Number: (888) 203-1112 (US/Canada) and (719) 457-0820 (International)
> Replay Access Code: 1154820 - Replay will be available throughMarch 15, 2013

UPCOMING CONFERENCE SCHEDULE

41st Annual Howard Weil Energy Conference
 March 17 – March 21, 2013, New Orleans, LA
Northland Capital Markets Small-Cap Energy Summit
 March 12, 2013, New York, NY
IPAA 19th Annual Oil and Gas Investment Symposium
 April 15 – April 17, 2013, New York, NY

HEDGING UPDATE

The following table summarizes Northern's oil derivative contracts as ofFebruary 5, 2013 by fiscal quarter:

	COSTLESS COLLARS		SWAPS	
Contract Period	Volume (Bbls)	Weighted Average Floor/Ceiling Price (per Bbl)	Volume (Bbls)	Weighted Average Price (per Bbl)
2013:				
Q1	575,550	$89.71 - $103.87	210,000	$92.00
Q2	541,481	$89.83 - $103.91	255,000	$91.56
Q3	558,374	$90.36 - $104.23	285,000	$92.69
Q4	532,864	$90.45 - $104.29	330,000	$92.25
2014:				
Q1	60,000	$90.00 - $99.05	630,000	$92.28
Q2	60,000	$90.00 - $99.05	690,000	$92.04
Q3	60,000	$90.00 - $99.05	465,000	$91.11
Q4	60,000	$90.00 - $99.05	465,000	$91.11
2015:				
Q1	-	-	90,000	$90.50
Q2	-	-	90,000	$90.50

ABOUT NORTHERN OIL AND GAS, INC.

Northern Oil and Gas, Inc. is an exploration and production company with a core area of focus in the Williston Basin Bakken and Three Forks play inNorth Dakota and Montana.

More information about Northern Oil and Gas, Inc. can be found atwww.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 release regarding Northern'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 release, 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 Northern'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 Northern conducts business, changes in the interest rate environment, legislation or regulatory requirements, conditions of the securities markets, Northern'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 Northern's operations, products, services and prices.

Northern 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 Northern's control.

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NORTHERN OIL AND GAS, INC.
STATEMENTS OF COMPREHENSIVE INCOME

	Three Months Ended December 31,		Year Ended December 31,	
	2012	2011	2012	2011

REVENUES				
Oil and Gas Sales	$80,369,145	$53,235,604	$296,637,857	$159,439,508
Gain (Loss) on Settled Derivatives	4,337,766	(2,712,872)	(391,420)	(13,407,878)
Unrealized Gain (Loss) on Derivative Instruments	(2,978,806)	(23,602,774)	15,147,122	3,072,229
Other Revenue	18,579	66,250	179,331	285,234
Total Revenue	81,746,684	26,986,208	311,572,890	149,389,093
OPERATING EXPENSES				
Production Expenses	9,842,073	4,500,872	32,382,310	13,043,633
Production Taxes	7,655,862	4,112,412	28,485,594	14,300,720
General and Administrative Expense	4,076,619	3,510,897	22,645,315	13,624,892
Depletion of Oil and Gas Properties	26,645,265	14,852,963	98,427,159	40,815,426
Depreciation and Amortization	105,662	83,932	409,888	298,137
Accretion of Discount on Asset Retirement Obligations	25,031	35,750	86,193	56,055
Total Expenses	48,350,512	27,096,826	182,436,459	82,138,863
INCOME (LOSS) FROM OPERATIONS	33,396,172	(110,618)	129,136,431	67,250,230
OTHER INCOME (EXPENSE)				
Other Income	23,611	-	23,611	-
Interest Expense	(5,744,684)	(160,295)	(13,874,909)	(585,982)
Interest Income	57	125	1,263	567,452
Gain on Available for Sale Securities	-	-	-	215,092
Total Other Income (Expense)	(5,721,016)	(160,170)	(13,850,035)	196,562
INCOME (LOSS) BEFORE INCOME TAXES	27,675,156	(270,788)	115,286,396	67,446,792
INCOME TAX PROVISION	8,123,000	1,110,000	43,001,772	26,835,300
NET INCOME (LOSS)	$ 19,552,156	$ (1,380,788)	$ 72,284,624	$ 40,611,492
OTHER COMPREHENSIVE INCOME, NET OF TAX				
Unrealized Gains on Marketable Securities (Net of tax of $109,000 for the year ended December 31, 2011)	-	-	-	173,846
Reclassification of Derivative Instruments included in Income (Net of Tax of $117,000 for the three months ended December 31, 2011 and $39,000 and $448,000 for the years ended December 31, 2012 and 2011, respectively)	-	190,876	62,309	709,776
Total Other Comprehensive Income	-	190,876	62,309	883,622
COMPREHENSIVE INCOME	$ 19,552,156	$ (1,189,912)	$ 72,346,933	$ 41,495,114
Net Income Per Common Share - Basic	$ 0.31	$ (0.02)	$ 1.16	$ 0.66
Net Income Per Common Share - Diluted	$ 0.31	$ (0.02)	$ 1.15	$ 0.65
Weighted Average Shares Outstanding – Basic	62,711,369	62,028,912	62,485,836	61,789,289
Weighted Average Shares Outstanding - Diluted	63,214,075	62,028,912	62,869,079	62,195,340

NORTHERN OIL AND GAS, INC.
BALANCE SHEETS

	December 31, 2012	2011
CURRENT ASSETS		
Cash and Cash Equivalents	$ 13,387,998	$ 6,279,587
Trade Receivables	70,219,669	51,418,830
Advances to Operators	3,109,591	17,530,474
Prepaid Expenses	592,001	486,421
Other Current Assets	1,115,088	317,460
Derivative Instruments	4,095,197	-
Deferred Tax Asset	1,695,000	4,472,000
Total Current Assets	94,214,544	80,504,772
PROPERTY AND EQUIPMENT		
Oil and Natural Gas Properties, Full Cost Method of Accounting		
Proved	1,159,191,601	566,195,321
Unproved	82,926,384	137,784,903
Other Property and Equipment	3,158,224	2,988,641
Total Property and Equipment	1,245,276,209	706,968,865
Less - Accumulated Depreciation and Depletion	162,031,493	63,265,919
Total Property and Equipment, Net	1,083,244,716	643,702,946
DERIVATIVE INSTRUMENTS	1,763,008	-
DEBT ISSUANCE COSTS	11,713,030	1,386,201
TOTAL ASSETS	1,190,935,298	$ 725,593,919

LIABILITIES AND STOCKHOLDERS' EQUITY

	2012	2011
CURRENT LIABILITIES		
Accounts Payable	$ 95,822,162	$ 110,133,286
Accrued Expenses	2,454,085	65,443
Accrued Interest	2,180,416	98,798
Derivative Instruments	-	9,363,068
Total Current Liabilities	100,456,663	119,660,595
LONG-TERM LIABILITIES		
Revolving Credit Facility	124,000,000	69,900,000
8% Senior Notes Due 2020	300,000,000	-
Derivative Instruments	2,547,745	2,574,903
Other Noncurrent Liabilities	1,570,630	959,366
Deferred Tax Liability	76,175,000	35,929,000
Total Long-Term Liabilities	504,293,375	109,363,269
TOTAL LIABILITIES	604,750,038	229,023,864
COMMITMENTS AND CONTINGENCIES (NOTE 9)		
STOCKHOLDERS' EQUITY		
Preferred Stock, Par Value $.001; 5,000,000 Authorized, No Shares Outstanding	-	-
Common Stock, Par Value $.001; 95,000,000 Authorized (12/31/2012 – 63,532,622 Shares Outstanding and 12/31/2011 – 63,330,421 Shares Outstanding)	63,532	63,330
Additional Paid-In Capital	465,466,420	448,198,350
Retained Earnings	120,655,308	48,370,684
Accumulated Other Comprehensive Loss	-	(62,309)
Total Stockholders' Equity	586,185,260	496,570,055
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 1,190,935,298	$ 725,593,919

Northern Oil and Gas, Inc.

Reconciliation of Adjusted EBITDA
(UNAUDITED)

	Three Months Ended December 31,		Year Ended December 31,	
	2012	2011	2012	2011
	(in thousands)			
Net Income (Loss)	$ 19,552	$ (1,381)	$ 72,285	$ 40,611
Add Back:				
Interest Expense	5,745	160	13,875	586
Income Tax Provision	8,123	1,110	43,002	26,835
Depreciation, Depletion, Amortization and Accretion	26,776	14,973	98,923	41,170
Non-Cash Share Based Compensation	1,086	612	12,382	6,164
Unrealized Loss (Gain) on Derivative Instruments	2,979	23,603	(15,147)	(3,072)
Adjusted EBITDA	$ 64,261	39,077	$ 225,320	$ 112,294

NORTHERN OIL AND GAS, INC.
Reconciliation of GAAP Net Income to Adjusted Net Income
(UNAUDITED)

	Three Months Ended December 31,		Year Ended December 31,	
	2012	2011	2012	2011
	(in thousands, except share and per common share data)			
Net Income (Loss)	$ 19,552	$ (1,381)	$ 72,285	$ 40,611
Add:				
Unrealized (Gain) Loss on Derivative Instruments, Net of Tax (a)	1,415	14,655	(9,497)	(1,849)
Severance Expense, Net of Tax (b)	470	-	3,424	-
Adjusted Net Income	$ 21,437	$ 13,274	$ 66,212	$ 38,762
Weighted Average Shares Outstanding – Basic	62,711,369	62,028,912	62,485,836	61,789,289
Weighted Average Shares Outstanding – Diluted	63,214,075	62,436,366	62,869,079	62,195,340
Net Income Per Common Share – Basic	$ 0.31	$ (0.02)	$ 1.16	$ 0.66
Add:				
Change due to Unrealized (Gain) Loss on Derivative Instruments, Net of Tax	0.02	0.23	(0.15)	(0.03)
Change due to Severance Expense, Net of Tax	0.01	-	0.05	-
Adjusted Net Income Per Common Share – Basic	$ 0.34	$ 0.21	$ 1.06	$ 0.63
Net Income Per Common Share – Diluted	$ 0.31	$ (0.02)	$ 1.15	$ 0.65
Add:				
Change due to Unrealized (Gain) Loss on Derivative Instruments, Net of Tax	0.02	0.23	(0.15)	(0.03)
Change due to Severance Expense, Net of Tax	0.01	-	0.05	-
Adjusted Net Income Per Common Share – Diluted	$ 0.34	$ 0.21	$ 1.05	$ 0.62

(a) Adjusted to reflect related tax benefit (expense) of $1.6 million and $8.9 million for the three months ended December 31, 2012 and 2011, respectively and ($5.6 million) and ($1.2 million) for the years ended December 31, 2012 and 2011 respectively.

(b) Reflects severance expense recognized in connection with the departures during 2012 of our former president and former chief operating officer. Adjusted to reflect related tax benefit of $0.1 million for the three months ended December 31, 2012, and $2.0 million for the year ended December 31, 2012.

Proved Reserves Summary at December 31, 2012(1)

Reserve Category	**Crude Oil (MBbls)**	**Natural Gas (MMcf)**	**2012 MBoe**(2)	**2011 MBoe**(2)	**% Change**	**2012 Pre-Tax PV10% ($MM)**(3)
Proved Developed Producing	23,679	15,014	26,181	14,605	79	795
Proved Developed Non-Producing	3,667	2,336	4,056	1,142	255	43
Proved Undeveloped	33,368	23,928	37,356	31,074	20	449
Total Proved	60,714	41,278	67,594	46,822	44	1,287

(1) Northern'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, 2012 are estimated assuming a constant realized price of $84.92 per barrel of crude oil and a constant realized price of $4.78 per Mcf of natural gas, which includes an uplift factor of 1.7 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 2012 to December 2012, which are then adjusted to reflect applicable transportation and quality differentials.

(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, 2012, the Company's discounted future income taxes were $246.1 million and the standardized measure of after-tax discounted future net cash flows was $1,041.4 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'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%)	$ 1,287,406

Future income taxes, discounted at 10%	246,051
Standardized measure of discounted future net cash flows	$ 1,041,355

Uncertainties are inherent in estimating quantities of proved reserves, including many risk factors beyond Northern'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'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's properties will vary from reserve estimates.

SOURCE Northern Oil and Gas, Inc.