QEP Resources Reports 2011 EBITDA of $1.39 Billion and Production of 275.2 Bcfe

February 22, 2012

Company replaces 313% of production and grows year-end 2011 proved crude oil and NGL reserves 107%

DENVER, Feb. 22, 2012 /PRNewswire/ -- QEP Resources (NYSE: QEP) reported adjusted EBITDA (a non-GAAP measure) of $1,386.6 million for 2011 compared to $1,140.5 million in 2010, a 22% increase. Factors driving QEP's results included 20% higher net production and 54% higher oil and NGL production from QEP Energy, increased gathering and processing margins at QEP Field Services, and higher net realized crude oil and NGL prices which more than offset net realized natural gas prices that were 11% lower than in the previous year at QEP Energy. Adjusted EBITDA in the fourth quarter of 2011 was $390.5 million compared to $298.5 million a year earlier, a 31% increase.

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ADJUSTED EBITDA BY SUBSIDIARY

	Three Months Ended December 31,			Year Ended December 31,		
	2011	2010	Change	**2011**	2010	Change
			(in millions)			
QEP Energy	**$ 300.5**	$ 242.4	24%	**$ 1,057.5**	$ 926.2	14%
QEP Field Services	**87.2**	52.4	66%	**320.3**	203.9	57%
QEP Marketing and other	**2.8**	3.7	-24%	**8.8**	10.4	-15%
Total Adjusted EBITDA (1)	**$ 390.5**	$ 298.5	31%	**$ 1,386.6**	$ 1,140.5	22%

(1) See attached schedule for a reconciliation of Adjusted EBITDA to net income.

QEP Resources net income from continuing operations for 2011 was $267.2 million or $1.50 per diluted share, compared to $283.0 million or $1.60 per diluted share in 2010. QEP Resources had a net loss from continuing operations in the fourth quarter of 2011 of $0.3 million or no earnings per diluted share, compared to net income of $65.0 million or $0.37 per diluted share a year earlier. The net loss in the fourth quarter of 2011 was attributed to a non-cash price-related impairment charge of $195.2 million on some of its mature, dry gas, and higher cost properties in both the Northern and Southern Regions. See Financial and Operating Results for additional information.

Excluding changes in unrealized gains and losses on natural gas basis-only swaps, gains and losses on asset sales, non-cash price-related impairment charge, separation costs and losses on early extinguishment of debt, QEP Resources adjusted net income from continuing operations (a non-GAAP measure) was $316.2 million or $1.77 per diluted share in 2011 compared to $217.8 million or $1.23 per diluted share in 2010. Similarly adjusted fourth quarter 2011 net income from continuing operations was $104.6 million or $0.58 per diluted share compared to net income of $44.8 million or $0.25 per diluted share in the year earlier period.

NET INCOME BY SUBSIDIARY

	Three months ended December 31,			Year Ended December 31,		
	2011	2010	Change	**2011**	2010	Change
			(in millions, except per share amounts)			
QEP Energy (1)	**$ (43.5)**	$ 38.9	-212%	**$ 104.7**	$ 203.9	-49%
QEP Field Services (2)	**40.3**	22.6	78%	**154.5**	91.1	70%
QEP Marketing and other	**2.9**	3.1	-6%	**8.4**	6.7	25%
QEP Resources	**-**	0.4	-100%	**(0.4)**	(18.7)	-98%
Income from continuing operations (2)	**(0.3)**	65.0	-100%	**267.2**	283.0	-6%
Discontinued operations (3)	**-**	-	-	**-**	43.2	-100%
NET INCOME (2)	**$ (0.3)**	$ 65.0	-100%	**$ 267.2**	$ 326.2	-18%
Earnings per diluted share						
From continuing operations	**$ -**	$ 0.37		**$ 1.50**	$ 1.60	
Total earnings	**$ -**	$ 0.37		**$ 1.50**	$ 1.84	
Weighted-average diluted shares	**178.2**	177.4		**178.4**	177.3	

(1) During the fourth quarter of 2011, QEP Energy recorded a non-cash price-related impairment charge of $195.2 million on some of its mature, dry gas, and higher cost properties in both the Northern and Southern Regions. See Financial and Operating Results for additional information.
(2) Net income represents amounts attributable to QEP Resources after deducting non-controlling interest.
(3) QEP Resources completed its tax-free spin-off from Questar Corporation on June 30, 2010. In conjunction with the spin-off, QEP Resources distributed the common stock of its wholly owned subsidiary, Wexpro Company, to Questar. Accordingly, Wexpro's historical financial results have been presented as discontinued operations in this release.

"QEP Resources completed another successful year in 2011," said Chuck Stanley, President and CEO. "QEP Energy production was up 20% from last year, driven by strong results from the Pinedale Anticline and Haynesville Shale plays, combined with significant contributions from new wells in our Woodford "Cana" Shale and Bakken/Three Forks plays. With 68% of our 2011 drilling capital directed to oil and liquids-rich gas plays, we grew oil and NGL production 54% and year-end proved crude oil and NGL reserves 107% compared to 2010. Crude oil and NGL production accounted for 29% of QEP Energy net realized production revenues for the year and we expect that share to grow as we allocate more of our 2012 QEP Energy capital to our higher-margin oil and liquids-rich gas resource plays. Our midstream business, QEP Field Services, had an excellent year, thanks to a combination of great execution coupled with strong gas processing margins. Our new Blacks Fork II plant continues to perform well, and the midstream team is now focused on new projects to drive additional growth in 2012 and beyond," Stanley added.

Financial and Operating Results

- QEP Energy grew natural gas, oil and NGL net production to 275.2 billion cubic feet of natural gas equivalent (Bcfe) compared to 229.0 Bcfe in 2010. Crude oil and NGL comprised 14% of reported production volumes.
- QEP Energy Adjusted EBITDA increased 14% compared to 2010, driven by a 20% increase in production and increased net realized liquid prices – 30% for crude oil and 22% for NGL, partially offset by an 11% decrease in net realized natural gas prices.
- QEP Energy net realized natural gas prices averaged $4.74 per thousand cubic feet (Mcf), compared to $5.32 per Mcf in 2010. Field-level natural gas prices in 2011 were $3.95 per Mcf compared to $4.18 per Mcf in 2010. Natural gas-related derivative settlements contributed $187.8 million in 2011 ($0.79 per Mcf) compared to $232.1 million in 2010 ($1.14 per Mcf).
- QEP Energy net crude oil and NGL revenues (including the settlement of crude oil-related derivatives) increased 85% compared to 2010 and represented 29% of net realized production revenues.
- Net realized crude oil prices averaged $86.63 per barrel, up 30% compared to 2010. Oil related derivative settlements contributed $1.6 million in 2011 ($0.43 per bbl) compared to a loss of $8.7 million in 2010 ($2.91 per bbl).
- Net realized NGL prices at QEP Energy averaged $47.76 per barrel, up 22% compared to the 2010.
- QEP Field Services Adjusted EBITDA increased 57% compared to 2010, driven by a 22% increase in gathering margin and a 93% increase in processing margin. Net income was $154.5 million, up 70% compared to the 2010.
- QEP Energy 2011 capital investment (on an accrual basis) was $1,338.8 million comprised of $1,290.8 million in drilling and completion and other expenditures (including $0.3 million of dry hole exploration expense) and $48.0 million in property acquisition costs.
- QEP Field Services 2011 capital investments (on an accrual basis) to expand capacity at its gathering, processing and treating facilities in western Wyoming, eastern Utah and the Haynesville/Cotton Valley area of northwest Louisiana totaled $101.6 million.
- Field Services introduced gas into the Blacks Fork II plant on July 14th. QEP Energy entered into a fee-based processing agreement with QEP Field Services under which QEP Field Services provides cryogenic gas processing services for QEP Energy's Pinedale production volumes at Blacks Fork II effective August 1, 2011.
- Separation costs and losses on early extinguishment of debt reduced QEP Resources pre-tax income from continuing operations by $0.7 million in 2011 compared to $26.8 million in 2010.
- Through December 31, 2011, QEP designated most of its natural gas, oil and NGL derivative contracts as cash flow hedges, whose unrealized fair value gains and losses were recorded to accumulated other comprehensive income on QEP's balance sheet. Effective January 1, 2012, the Company has elected to de-designate all of its natural gas, oil and NGL derivative contracts that had previously been designated as cash flow hedges at December 31, 2011, and has elected to discontinue hedge accounting prospectively.
- During the year ended December 31, 2011, QEP revised its reporting of transportation and handling costs to appropriately reflect revenues and expenses in accordance with GAAP and industry practice. The transportation and other handling costs are recast on the Consolidated Income Statement from revenues to "Natural gas, oil and NGL transportation and other handling costs." All prior periods have been adjusted to reflect the current year presentation. The impact of this revision is immaterial and has no effect on net income and Adjusted EBITDA.
- During the fourth quarter of 2011, QEP recorded a non-cash price related impairment charge of $195.2 million on some of its mature, dry gas, and higher cost properties in both the Northern and Southern Regions. The impairment charge related to the reduced value of these areas resulting from lower natural gas prices and the current forward curve for natural gas prices. The assets were written down to their estimated fair values. Of the $195.2 million impairment charge, $163.5 million related to properties in the Northern Region with the remaining $31.7 million related to properties in the Southern Region.

QEP 2012 Adjusted EBITDA, Capital Expenditure and Production Guidance

Due to a dramatic decrease in 2012 natural gas prices, QEP now expects 2012 Adjusted EBITDA to range from $1,350 to $1,450 million, compared to a previously forecasted range of $1,450 to $1,550 million. QEP Energy expects 2012 production should range from 305 to 310 Bcfe, unchanged from the previously forecasted range.

The company's guidance assumes commodity derivative positions in place on the date of this release and other assumptions summarized in the table below:

Guidance and Assumptions

	2012	
	Current Forecast	Previous Forecast
QEP Resources Adjusted EBITDA (millions)	$1,350 - $1,450	$1,450 - $1,550
QEP Energy capital investment (millions)	$1,130 - $1,280	$1,330
QEP Field Services capital investment (millions)	$170	$170
QEP Marketing and other capital investment (millions)	-	-
Total QEP Resources capital investment (millions)	$1,300 - $1,450	$1,500
QEP Energy production - Bcfe	305 - 310	305 - 310
NYMEX gas price per MMBtu (1)	$2.00 - $3.00	$3.75 - $4.25
NYMEX crude oil price per bbl (1)	$90.00 - $100.00	$90.00 - $100.00
NYMEX/Rockies basis differential per MMBtu (1)	$0.20 - $0.15	$0.20 - $0.15
NYMEX/Midcontinent basis differential per MMBtu (1)	$0.20 - $0.15	$0.20 - $0.15

(1) For remaining 2012 un-hedged volumes

Approximately 65% of QEP Energy's forecasted natural gas production, 56% of forecasted oil production and 18% of forecasted NGL production for 2012 is subject to commodity derivatives. On a natural gas equivalent basis, the company has approximately 60% of its forecasted production for 2012 subject to commodity derivatives. A table with details of the company's positions is included at the end of this release.

In response to current commodity prices, the company is decreasing its capital allocated to the Haynesville Shale and other dry gas development areas and plans to allocate 88% of its 2012 capital to higher return projects including Pinedale, the Uinta Basin Red Wash Mesaverde play, the Bakken, and oil-directed horizontal drilling in the Powder River Basin and Midcontinent. In response to growing QEP Energy and third-party demand, QEP Field Services will begin construction on Iron Horse II, a new 150 MMcfd fee-based cryogenic gas processing plant in the Uinta Basin.

QEP Energy Results

QEP Energy's 2011 production increased 20% to 275.2 Bcfe compared to 229.0 Bcfe in the 2010 period. The Southern Region (formerly the Midcontinent region) contributed 56% of total production compared to 53% in 2010.

QEP Energy - Production by Major Area

	Three months ended December 31,			Year Ended December 31,			
	2011	2010	Change	**2011**		2010	Change
				(in Bcfe)			
Southern Region							
Haynesville/Cotton Valley	**26.6**	22.4	19%	**107.5**	-	79.8	35%
Midcontinent	**12.7**	10.9	17%	**46.2**	-	40.6	14%
Total Southern Region	**39.3**	33.3	18%	**153.7**		120.4	28%
Northern Region							
Pinedale Anticline	**23.8**	18.6	28%	**79.4**	-	68.5	16%
Uinta Basin (1)	**4.6**	5.5	-16%	**20.8**	-	21.4	-3%
Rockies Legacy	**6.2**	4.7	32%	**21.3**	-	18.7	14%
Total Northern Region	**34.6**	28.8	20%	**121.5**		108.6	12%
Total production	**73.9**	62.1	19%	**275.2**		229.0	20%

(1) Includes 1.6 Bcfe in Q1 2011 from prior periods due to a change in ownership interest in a federal unit.

QEP Energy - Commodity Prices (1)

	Three months ended December 31,			Year Ended December 31,		
	2011	2010	Change	**2011**	2010	Change
Natural gas price ($ per Mcf)						
Average field-level natural gas price	**$ 3.66**	$ 3.65	0%	**$ 3.95**	$ 4.18	-6%
Natural gas hedging impact (2)	**1.59**	2.07	-23%	**1.29**	1.74	-26%
Average revenue	**5.25**	5.72	-8%	**5.24**	5.92	-11%
Realized losses on basis-only swaps (3)	**(0.51)**	(0.58)	-12%	**(0.50)**	(0.60)	-17%
Net realized natural gas price	**$ 4.74**	$ 5.14	-8%	**$ 4.74**	$ 5.32	-11%
Oil price ($ per bbl)						
Average field-level oil price	**$ 87.01**	$ 72.50	20%	**$ 86.20**	$ 69.39	24%
Oil hedging impact (2)	**0.55**	(4.20)	-113%	**0.43**	(2.91)	-115%
Net realized oil price	**$ 87.56**	$ 68.30	28%	**$ 86.63**	$ 66.48	30%

NGL price ($ per bbl)						
Average field-level NGL price	**$ 56.34**	$ 39.30	43%	**$ 47.76**	$ 39.04	22%

(1) Recast to reflect exclusion of natural gas, oil and NGL transportation and other handling costs.
(2) Reported in revenues in the consolidated income statement.
(3) Reported below operating income in the consolidated income statement.

QEP Energy - Operating Expenses

	Three months ended December 31,			Year Ended December 31,		
	2011	2010	Change	**2011**	2010	Change
			(per Mcfe)			
Depreciation, depletion and amortization	**$ 2.48**	$ 2.58	-4%	**$ 2.57**	$ 2.59	-1%
Lease operating expense	**0.57**	0.58	-2%	**0.54**	0.56	-4%
Natural gas, oil and NGL transportation and other handling costs	**0.75**	0.57	32%	**0.68**	0.55	24%
General and administrative expense	**0.39**	0.36	8%	**0.36**	0.34	6%
Allocated interest expense	**0.29**	0.31	-6%	**0.30**	0.34	-12%
Production taxes	**0.34**	0.32	6%	**0.36**	0.34	6%
Total Operating Expenses	**$ 4.82**	$ 4.72	2%	**$ 4.81**	$ 4.72	2%

- Depreciation, depletion and amortization expense per Mcfe (the DD&A rate) decreased in the fourth quarter and full year 2011 compared to 2010 primarily as the result of booking additional NGL reserves in Pinedale associated with the Blacks Fork II processing plant and the addition of lower cost reserves in the Haynesville/Cotton Valley area.
- Lease operating expense per Mcfe decreased in full year 2011 compared to 2010 as a result of increased production volumes in lower operating cost areas. Growing production from high-rate, low-operating cost wells in the Haynesville/Cotton Valley area and Pinedale coupled with declining production from higher cost areas lowered average per Mcfe lease operating expense. For the quarter, lease operating expenses per Mcfe were slightly lower for the same reasons as the full year decrease.
- Natural gas, oil and NGL transportation and other handling costs per Mcfe were 24% higher in 2011 than in 2010, due primarily to processing fees associated with increased NGL production and related transportation costs under a revised processing agreement at Pinedale. Natural gas, oil and NGL transportation and other handling costs per Mcfe were $0.18 per Mcfe higher in the fourth quarter of 2011 than in the 2010 fourth quarter.
- General and administrative (G&A) expense per Mcfe increased in the three and twelve months ended December 31, 2011, as the result of higher employee benefit and stock compensation plan related expenses, increased legal and outside professional services and higher insurance costs which were partially offset by increased production in the three and twelve months ended December 31, 2011.
- Production taxes per Mcfe increased in the current year periods compared to 2010 as the result of increased field-level crude oil and NGL prices.
- QEP Energy total cash cost of production lease operating expense plus general and administrative expense, allocated interest, and production taxes – was $1.56 per Mcfe in 2011, compared to $1.58 per Mcfe in 2010, a 1% decrease.

Year end 2011 proved reserves increase

QEP Energy's estimated proved reserves totaled 3.6 Tcfe at December 31, 2011, up 19% from year-end 2010. Excluding price-related revisions, QEP Energy replaced 313% of 2011 production. Including price-related revisions, the reserve replacement ratio was 312% (a positive 2.1 Bcfe of price related revisions). Total combined proved crude oil and NGL reserves increased 107% from year-end 2010, driven by strong results from QEP's development program in the Bakken/Three Forks play and reserves added as a result of the completion of the Blacks Fork II plant. Approximately 24% of total proved reserves at year-end 2011 were crude oil and NGL compared to 14% at year-end 2010. Total proved developed reserves comprised 2.0 Tcfe, or 54% of the total. A reconciliation of reported quantities of proved reserves is summarized in the table below:

	Natural Gas	Oil	NGL	Natural Gas Equivalents
	(Bcf)	(Mbbl)	(Mbbl)	(Bcfe)
Total proved reserves at December 31, 2010	2,612.9	52,276.7	17,369.5	3,030.7
Revisions of previous estimates	**(270.1)**	**1,794.0**	**39,290.5**	**(23.5)**
Extensions and discoveries	**641.9**	**17,360.4**	**22,600.7**	**881.6**
Purchase of reserves in place	**1.9**	**17.0**	**12.0**	**2.1**
Sale of reserves in place	**(0.8)**	**(192.0)**	**-**	**(1.9)**
Production	**(236.4)**	**(3,741.3)**	**(2,715.6)**	**(275.2)**
Total proved reserves at December 31, 2011	**2,749.4**	**67,514.8**	**76,557.1**	**3,613.8**

Details on year-end 2011 proved reserves by division or operating area, proved reserve category and percentage of total proved reserves comprised of crude oil and NGL (liquids) are as follows:

	Total (in Bcfe)	% of total	PUD %	% liquids
Southern Region				
Haynesville/Cotton Valley	**782.9**	**22%**	**46%**	**-**
Midcontinent	**518.7**	**14%**	**36%**	**31%**
Northern Region				
Pinedale Anticline	**1,531.0**	**42%**	**47%**	**23%**
Uinta Basin	**393.6**	**11%**	**46%**	**23%**
Rockies Legacy	**387.6**	**11%**	**50%**	**68%**
Total QEP Energy	**3,613.8**	**100%**	**46%**	**24%**

For comparison, the year-end 2010 proved reserves by division or operating area, proved reserve category and percentage of total proved reserves comprised of crude oil and NGL (liquids) were as follows:

	Total (in Bcfe)	% of total	PUD %	% liquids
Southern Region				
Haynesville/Cotton Valley	**728.3**	**24%**	**55%**	**-**
Midcontinent	**442.2**	**15%**	**32%**	**10%**
Northern Region				
Pinedale Anticline	**1,348.9**	**44%**	**55%**	**5%**
Uinta Basin	**212.8**	**7%**	**-**	**35%**
Rockies Legacy	**298.5**	**10%**	**47%**	**57%**
Total QEP Energy	**3,030.7**	**100%**	**47%**	**14%**

The trailing twelve-month weighted-average prices used to estimate QEP's year-end 2011 proved reserves were $3.46/Mcf for natural gas, $82.96/bbl for crude oil, and $41.55/bbl for NGL. Average natural gas prices were 10% lower, average oil prices were 26% higher, and average NGL prices were 6% higher than the applicable prices used to estimate year-end 2010 proved reserves. QEP's estimated proved reserves at December 31, 2011, were prepared by Ryder Scott Company L.P., independent petroleum engineers, in accordance with Securities and Exchange Commission regulations.

QEP Energy Operations Update

QEP adds 105 Pinedale well completions in 2011
At the Pinedale Anticline field in western Wyoming, QEP completed and turned to sales 105 new wells during 2011, including 16 new wells since the third quarter 2011 release. Drilling and completion efficiencies have allowed QEP to maintain industry-leading average gross completed well costs of $3.9 million per well in 2011. The average drill time from spud to total depth was 13.8 days in 2011, down from an average of 17 days in 2010. During the fourth quarter of 2011, QEP's Pinedale net production averaged approximately 258 MMcfed. As a result of the fee-based processing agreement entered into between QEP Energy and QEP Field Services effective August 1, 2011, QEP Energy average net equivalent production for the fourth quarter included a significant contribution from liquids (208 MMcf/day, 1,792 Bbl Oil/day and 6,637 Bbl NGL/day). The company suspends completion operations at Pinedale during the coldest months of the winter (generally from December through mid-March). QEP currently has 37 wells drilled and cased and waiting on completion. The company plans to operate 6 rigs at Pinedale for most of 2012.

Slides with maps and other supporting materials referred to in this release are posted on the Company's website www.qepres.com. Please refer to slides 5 and 6 for additional details on Pinedale.

Bakken/Three Forks oil production growth continues on QEP's 90,000 acre North Dakota leasehold
In the Williston Basin of North Dakota, QEP has completed and turned to sales 7 new Bakken and 4 new Three Forks Formation company-operated wells since the third quarter release. QEP's working interest in these wells ranges from 63% to 100%. The company operates 30 producing wells in the play (24 Bakken and 6 Three Forks) and has a working interest in 93 producing wells that are operated by others. During the fourth quarter of 2011, QEP's Bakken/Three Forks net production averaged approximately 5,019 Boepd.

QEP has 2 operated wells currently drilling and 2 operated wells waiting on completion. The company also has interests in 7 outside-operated wells currently being drilled and 13 outside-operated wells that are waiting on completion. Working interests in outside operated wells range from less than 1% to 13%.

The company has 2 rigs currently working in the play. A third rig will begin drilling on a 10-well pad within the next month. QEP currently estimates that the average completed well cost for a typical Bakken/Three Forks well (10,000' average lateral length) will range from $9.4 to $9.7 million in 2012. Slide 7 shows QEP's acreage and activity in the Bakken/Three Forks play.

Strong industry activity continues in the Woodford "Cana" Shale play
The company has completed and turned to sales 4 new QEP-operated Woodford "Cana" Shale wells in western Oklahoma since the last update. The company currently operates 25 producing wells and has working interests in an additional 197 producing Cana wells that are operated by others. During the fourth quarter of 2011, QEP net production from the play averaged approximately 49 MMcfed.

QEP has 2 operated wells currently drilling and 1 operated well waiting on completion and has interests in 6 wells currently being drilled and 12 wells waiting on completion that are operated by others. QEP plans to operate 2 to 3 rigs for the balance of 2012 in the liquids-rich gas portion of the core of the Cana play, with the majority of the activity focused on development drilling on 80-acre density. Slide 8 depicts QEP's acreage and additional details on the Cana play.

QEP commences development drilling in liquids-rich gas Mesaverde play in Uinta Basin
In the Uinta Basin of eastern Utah, QEP has commenced a two-rig vertical development drilling program targeting liquids-rich gas stacked sands in the Mesaverde Formation at average drill depths of 11,000 feet. The company has a 100% working interest in over 32,000 acres within the Red Wash Federal Unit, which it believes could be prospective for development of this emerging play.

At the end of 2011, the company had 20 producing wells in the play. QEP plans to drill at least 40 additional wells in the play in 2012. The company estimates gross completed well costs should average about $2.1 million with average gross per well estimated ultimate recoveries of 2.1 Bcfe. Slide 9 depicts QEP's acreage and additional details on the Mesaverde play.

Granite Wash, Tonkawa and Marmaton horizontal development in the Texas Panhandle and Western Oklahoma
In the Texas Panhandle Granite Wash play, the company has completed and turned to sales one additional QEP operated Cherokee horizontal well and one additional Caldwell zone horizontal well in Wheeler County, Texas since the last operations update. QEP has a 59% working interest in both newly completed wells. QEP has a working interest in a total of 61 producing horizontal Granite Wash/Atoka Wash wells in the Texas Panhandle. During the fourth quarter of 2011, net production from this play (vertical and horizontal wells) averaged approximately 52 MMcfed. The company participated with a working interest in 5 outside-operated Granite Wash wells in the Texas Panhandle that were completed since the last operations update with working interests ranging from less than 1% to 23%. QEP is also participating in 6 outside-operated wells that are waiting on completion with working interests ranging from 2% to 19% and 4 outside-operated wells currently drilling with working interests ranging from 27% to 33%.

Excluding 7 wells completed in the Atoka formation which produces primarily gas, QEP participated in a total of 25 completed horizontal wells (both operated and non-operated) during 2011 in Wheeler County, Texas. The initial 30-day average rate for these 25 wells was approximately 1,460 Boepd.

In addition, since the last update QEP has drilled and completed 3 new Marmaton, 1 Tonkawa, and 1 Skinner horizontal oil wells in western Oklahoma and participated with a working interest in 8 outside operated wells in these plays with working interests ranging from 1% to 38%.

QEP participated in a total of 7 completed Marmaton horizontal wells (both operated and non-operated) during 2011 in western Oklahoma. The initial 30-day average rate for these wells was approximately 360 Boepd. QEP participated in a total of 27 completed Tonkawa horizontal wells (both operated and non-operated) during 2011 in western Oklahoma. The initial 30-day average rate for these wells was approximately 350 Boepd.

QEP currently has 2 rigs running in the combined Granite Wash/Marmaton/Tonkawa plays. See slide 10 for details on the Granite Wash play.

Reducing rig count in the Haynesville Shale of NW Louisiana
QEP has completed 11 additional company-operated Haynesville wells, since the last update, each with strong production rates and pressures. QEP drill times in the play averaged 32 days from spud to total depth in 2011, down from 37 days in 2010. QEP believes that improved drilling performance and completion efficiencies have allowed QEP to remain the lowest cost operator in its portion of the Haynesville play. QEP-operated gross completed well costs averaged $9.1 million in 2011 compared to $9.3 million in 2010. The company operates 108 producing wells in the play and has a working interest in 121 producing wells that are operated by others. During the fourth quarter of 2011, the company's Haynesville net production averaged approximately 239 MMcfd and Cotton Valley/Hosston net production averaged approximately 50 MMcfd. QEP net production from the Haynesville play continues to be impacted by the Company's decision to restrict the flowing rate of Haynesville wells to decrease near-wellbore pressure drawdown. The Company continues to restrict flow rates to minimize reservoir and propped fracture damage, which should lead to increased ultimate recoverable reserves.

QEP has 18 wells waiting on completion or being completed and currently has one operated rig working in the Haynesville play, down from a peak of 6 rigs in 2011. The Company also participated in 6 outside-operated Haynesville wells that were completed and turned to sales since the last operations update with working interests ranging from less than 1% to 12%. QEP has interests in 4 outside-operated Haynesville wells that are waiting on completion. Refer to slide 11 for additional information on QEP's Haynesville activities.

QEP Field Services Results
QEP Field Services (Field Services) Adjusted EBITDA increased 57% to $320.3 million compared to $203.9 million in 2010. During the fourth quarter of 2011, Adjusted EBITDA increased 66% to $87.2 million from the 2010 fourth quarter. Adjusted EBITDA increased for the year and quarter ended December 31, 2011, due to higher gathering and processing margins.

- Gathering margin (total gathering revenues less gathering related operating expenses) increased 22%, or $33.4 million, compared to 2010, driven primarily by increased other gathering revenue related to a third-party processing arrangement for certain gas volumes in the Northern Region and a 6% increase in revenues from gathering fees. During the fourth quarter of 2011, gathering margin increased 4%, or $1.4 million compared to 2010. Total system throughput volume at end of the year averaged 1.4 million MMBtu per day.
- Processing margin (total processing plant revenues less plant operating expenses and shrinkage) increased 93%, or $79.7 million compared to 2010, driven primarily by keep-whole processing margins that were 95% higher and revenue from processing fees which were 53% higher. The increased keep-whole processing margin was primarily the result of a 34% increase in NGL prices and a 42% increase in NGL volumes. Processing margin in the fourth quarter of 2011 increased 129%, or $30.2 million, compared to the 2010 fourth quarter, driven primarily by keep-whole processing margins that were 130% higher. The increased keep-whole processing margin was primarily the result of a 31% increase in NGL prices and a 90% increase in NGL volumes.
- Approximately 70% of Field Services' 2011 net operating revenue was derived from fee-based gathering and processing activities compared to 78% in 2010. During the fourth quarter of 2011, approximately 62% of Field Services' net operating revenue was derived from fee-based gathering and processing activities compared to 77% in the 2010 period.
- Field Services gathering volumes totaled 495.4 million MMBtu in 2011 compared to 475.7 million MMBtu in 2010. For the

fourth quarter of 2011, gathering volumes were 128.4 million MMBtu compared to 121.2 million MMBtu in the 2010 fourth quarter.

- Fee-based processing revenues increased 53% compared to 2010, due to a 6% increase in fee-based processing volumes to 240.7 million MMBtu and a 38% increase in the average processing fee rate to $0.22 per MMBtu. During the fourth quarter of 2011, fee-based processing revenues increased 79%, due to a 3% increase in fee-based processing volumes and an 80% increase in the average processing fee rate to $0.27 per MMBtu.
- NGL sales volumes totaled 141.8 million gallons in 2011 compared to 100.2 million gallons in 2010, a 42% increase. NGL sales volumes totaled 43.6 million gallons during the 2011 fourth quarter, a 90% increased over the 2010 fourth quarter.
- Field Services put into service two new major processing plant facilities during 2011. The 150 MMcfd Iron Horse cryogenic gas processing plant in eastern Utah was commissioned in January 2011 and the 420 MMcfd Blacks Forks II cryogenic gas processing plant in southwest Wyoming was commissioned in July 2011. Both of these processing plants were major drivers in Field Services increased operating results during 2011. Field Services owns and operates processing plants in the Northern (Rocky Mountain) Region with an aggregate processing capacity of 1.37 Bcfd of natural gas.

Fourth Quarter 2011 Results Conference Call

QEP Resources management will discuss full year and fourth quarter 2011 results in a conference call on Thursday, February 23, beginning at 11:00 a.m. ET. The call can be accessed at www.qepres.com. A replay of the teleconference will be available on the website and from February 23rd to March 8th by dialing (855) 859-2056 in the U.S. or Canada and (404) 537-3406 for international calls, and then entering passcode 44233321. In addition, QEP's Fourth Quarter Operations Update Slides, with updated maps showing QEP's leasehold and current activity for key operating areas discussed in this release, can be found on the company's website.

About QEP Resources

QEP Resources, Inc. (NYSE:QEP) is a leading independent natural gas and oil exploration and production company with operations focused in the Rocky Mountain and Midcontinent of the United States. QEP Resources also gathers, compresses, treats, processes and stores natural gas.

Forward-Looking Statements

This release includes forward-looking statements within the meaning of Section 27(a) of the Securities Act of 1933, as amended, and Section 21(e) of the Securities Exchange Act of 1934, as amended. Forward-looking statements can be identified by words such as "anticipates", "believes", "forecasts", "plans", "estimates", "expects", "should", "will", or other similar expressions. Such statements are based on management's current expectations, estimates and projections, which are subject to a wide range of uncertainties and business risks. These forward-looking statements include statements regarding: forecasted Adjusted EBITDA, production and capital investment for 2012 and related assumptions for such guidance; number of rigs planned in operating areas; changes in lease operating expenses; the effects of restricting the flowing rate in the Haynesville Shale; estimated gross completed well costs and average estimated ultimate recoveries per well; QEP being the lowest cost operator in its portion of the Haynesville play; and anticipated growth from new projects of QEP Field Services. The Securities and Exchange Commission requires oil and gas companies, in their filings with the SEC, to disclose proved reserves that a company has demonstrated by actual production or through reliable technology to be economically and legally producible at specific prices and existing economic and operating conditions. The SEC permits optional disclosure of probable and possible reserves, however QEP has made no such disclosures in our filings with the SEC. QEP uses certain terms in our periodic news releases and other presentation materials such as "estimated ultimate recovery" (or "EUR"), "resource potential", and "net resource potential". These estimates are by their nature more speculative than estimates of proved, probable or possible reserves and accordingly are subject to substantially more risks of actually being realized. The SEC guidelines strictly prohibit us from including such estimates in filings with the SEC. Investors are urged to closely consider the disclosures and risk factors in our most recent annual report on Form 10-K and in other reports on file with the SEC. Actual results may differ materially from those included in the forward-looking statements due to a number of factors, including, but not limited to: the availability of capital; changes in local, regional, national and global demand for natural gas, oil and NGL; natural gas, NGL and oil prices; potential legislative or regulatory changes regarding the use of hydraulic fracture stimulation; impact of new laws and regulations, including the implementation of the Dodd-Frank Act; drilling results; shortages of oilfield equipment, services and personnel; operating risks such as unexpected drilling conditions; weather conditions; changes in maintenance and construction costs and possible inflationary pressures; the availability and cost of credit; and the other risks discussed in the Company's periodic filings with the Securities and Exchange Commission, including the Risk Factors section of the Company's Annual Report on Form 10-K for the year ended December 31, 2011.

QEP Resources undertakes no obligation to publicly correct or update the forward-looking statements in this news release, in other documents, or on the Web site to reflect future events or circumstances. All such statements are expressly qualified by this cautionary statement.

For more information, visit QEP Resources' website at: www.qepres.com.

The following table presents full year derivative positions as of February 16, 2012:

QEP Energy Hedge Positions - February 16, 2012

				Swaps	Collars	
Year	**Type of Contract**	**Index**	**Total**	**Average price per unit**	**Floor price**	**Ceiling price**
			(in millions)			
Natural gas sales (MMbtu)						
2012	Swap	IFCNPTE	2.8	$2.85		
2012	Swap	IFNPCR	76.9	4.97		
2012	Swap	IFPEPL	7.3	4.70		
2012	Swap	NYMEX	75.7	4.75		
2013	Swap	IFNPCR	65.7	5.66		

2013	Swap	NYMEX	29.2	3.68		
Oil sales (Bbls)						
2012	Swap	NYMEX WTI	1.8	$97.03		
2012	Collar	NYMEX WTI	1.3		$87.39	$115.37
2013	Swap	NYMEX WTI	0.2	105.80		
Ethane sales (Gals)						
2012	Swap	Mt. Belvieu Ethane	15.4	$0.64		
Propane sales (Gals)						
2012	Swap	Mt. Belvieu Propane	21.8	$1.28		

QEP Field Services Hedge Positions - February 16, 2012

Year	Type of Contract	Index	Total	Average Swap price per unit
			(in millions)	
Ethane sales (Gals)				
2012	Swap	Mt. Belvieu Ethane	15.4	$0.64
Propane sales (Gals)				
2012	Swap	Mt. Belvieu Propane	15.4	$1.36

QEP Marketing Hedge Positions - February 16, 2012

Year	Type of Contract	Index	Total	Average Swap price per unit
			(in millions)	
Natural gas sales (MMbtu)				
2012	Swaps	IFNPCR	3.3	$4.41
2013	Swaps	IFNPCR	0.9	4.77
Natural gas purchases (MMbtu)				
2012	Swaps	IFNPCR	0.3	$3.54

QEP RESOURCES, INC.
CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2011	2010	**2011**	2010
	(in millions, except per share amounts)			
REVENUES (1)				
Natural gas sales	**$ 318.0**	$ 311.9	**$ 1,239.1**	$ 1,205.3
Oil sales	**103.6**	56.6	**324.2**	198.1
NGL sales	**58.6**	17.4	**129.7**	47.9
Gathering, processing and other	**98.4**	64.4	**380.9**	251.3
Purchased gas and oil sales	**274.7**	137.6	**1,085.3**	598.0
Total Revenues	**853.3**	587.9	**3,159.2**	2,300.6
OPERATING EXPENSES				
Purchased gas and oil expense	**273.8**	133.9	**1,077.1**	589.3
Lease operating expense	**41.1**	35.3	**145.2**	125.0
Natural gas, oil and NGL transportation and other handling costs (1)	**29.0**	15.9	**102.2**	54.2
Gathering, processing and other	**27.9**	20.6	**107.3**	83.2
General and administrative	**34.1**	31.6	**123.2**	107.2
Separation costs	**-**	(0.7)	**-**	13.5
Production and property taxes	**26.9**	20.9	**105.4**	82.5
Depreciation, depletion and amortization	**199.0**	173.9	**765.4**	643.4
Exploration expenses	**3.0**	13.8	**10.5**	23.0
Abandonment and impairment	**202.0**	17.0	**218.4**	46.1
Total Operating Expenses	**836.8**	462.2	**2,654.7**	1,767.4
Net gain from asset sales	**-**	(0.2)	**1.4**	12.1
OPERATING INCOME	**16.5**	125.5	**505.9**	545.3
Interest and other income (loss)	**4.6**	(2.1)	**4.1**	2.3
Income from unconsolidated affiliates	**1.0**	0.5	**5.5**	3.0
Loss from early extinguishment of debt	**-**	-	**(0.7)**	(13.3)
Interest expense	**(23.0)**	(21.6)	**(90.0)**	(84.4)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	**(0.9)**	102.3	**424.8**	452.9
Income taxes	**1.6**	(36.5)	**(154.4)**	(167.0)
INCOME FROM CONTINUING OPERATIONS	**0.7**	65.8	**270.4**	285.9
Discontinued operations, net of income tax	**-**	-	**-**	43.2

NET INCOME	**0.7**	65.8	**270.4**	329.1
Net income attributable to noncontrolling interest	**(1.0)**	(0.8)	**(3.2)**	(2.9)
NET INCOME (LOSS) ATTRIBUTABLE TO QEP	**$ (0.3)**	$ 65.0	**$ 267.2**	$ 326.2
Earnings (Loss) Per Common Share Attributable to QEP				
Basic from continuing operations	**$ (0.01)**	$ 0.37	**$ 1.51**	$ 1.61
Basic from discontinued operations	**-**	-	**-**	0.25
Basic total	**$ (0.01)**	$ 0.37	**$ 1.51**	$ 1.86
Diluted from continuing operations	**$ -**	$ 0.37	**$ 1.50**	$ 1.60
Diluted from discontinued operations	**-**	-	**-**	0.24
Diluted total	**$ -**	$ 0.37	**$ 1.50**	$ 1.84
Weighted-average common shares outstanding				
Used in basic calculation	**176.7**	175.7	**176.5**	175.3
Used in diluted calculation	**178.2**	177.4	**178.4**	177.3

(1) During the year ended December 31, 2011, QEP revised its reporting of transportation and handling costs. Transportation and handling costs have been recast on the Consolidated Income Statement from revenues to "Natural gas, oil and NGL transportation and other handling costs" for all periods presented.

QEP RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	December 31,	
	2011	2010
	(in millions)	
ASSETS		
Current Assets		
Cash and cash equivalents	**$ -**	$ -
Accounts receivable, net	**397.4**	269.9
Fair value of derivative contracts	**273.7**	257.3
Inventories, at lower of average cost or market		
Gas, oil and NGL	**16.2**	16.4
Materials and supplies	**87.6**	65.4
Prepaid expenses and other	**43.7**	45.2
Total Current Assets	**818.6**	654.2
Property, Plant and Equipment (successful efforts method for gas and oil properties)		
Proved properties	**8,172.4**	6,874.3
Unproved properties, not being depleted	**326.8**	322.0
Midstream field services	**1,463.6**	1,360.5
Marketing and other	**49.8**	44.5
Total Property, Plant and Equipment	**10,012.6**	8,601.3
Less Accumulated Depreciation, Depletion and Amortization		
Exploration and production	**3,339.2**	2,454.4
Midstream field services	**297.5**	244.6
Marketing and other	**14.6**	12.3
Total Accumulated Depreciation, Depletion and Amortization	**3,651.3**	2,711.3
Net Property, Plant and Equipment	**6,361.3**	5,890.0
Investment in unconsolidated affiliates	**42.2**	44.5
Other Assets		
Goodwill	**59.5**	59.6
Fair value of derivative contracts	**123.5**	120.8
Other noncurrent assets	**37.6**	16.2
Total Other Assets	**220.6**	196.6
TOTAL ASSETS	**$ 7,442.7**	$ 6,785.3

	December 31,	
	2011	2010
	(in millions)	
LIABILITIES AND EQUITY		
Current Liabilities		
Checks outstanding in excess of cash balances	**$ 29.4**	$ 19.5
Accounts payable and accrued expenses	**457.3**	332.2
Production and property taxes	**40.0**	18.9
Interest payable	**24.4**	28.1

Fair value of derivative contracts	**1.3**	139.3
Deferred income taxes	**85.4**	27.8
Current portion of long-term debt	**-**	58.5
Total Current Liabilities	**637.8**	624.3
Long-term debt, less current portion	**1,679.4**	1,472.3
Deferred income taxes	**1,484.7**	1,377.7
Asset retirement obligations	**163.9**	148.3
Fair value of derivative contracts	**-**	0.3
Other long-term liabilities	**124.8**	99.3
Commitments and contingencies		
EQUITY		
Common stock - par value $0.01 per share; 500.0 million shares authorized; 177.2 million and 176.0 million shares issued at December 31, 2011 and 2010, respectively	**1.8**	1.8
Treasury stock - 0.4 million and 0.1 million shares at December 31, 2011 and 2010, respectively	**(13.1)**	(3.8)
Additional paid-in capital	**431.4**	398.0
Retained earnings	**2,673.5**	2,420.0
Accumulated other comprehensive income	**207.9**	194.3
Total Common Shareholders' Equity	**3,301.5**	3,010.3
Noncontrolling interest	**50.6**	52.8
Total Equity	**3,352.1**	3,063.1
TOTAL LIABILITIES AND EQUITY	**$ 7,442.7**	$ 6,785.3

QEP RESOURCES, INC.
CONSOLIDATED CASH FLOWS
(Unaudited)

	Year Ended December 31,	
	2011	2010
	(in millions)	
OPERATING ACTIVITIES		
Net income	**$ 270.4**	$ 329.1
Discontinued operations, net of income tax	**-**	(43.2)
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	**765.4**	643.4
Deferred income taxes	**156.8**	188.2
Abandonment and impairment	**218.4**	46.1
Share-based compensation	**22.0**	16.1
Amortization of debt issuance costs and discounts	**4.1**	2.4
Dry exploratory well expense	**0.3**	9.6
Net gain from asset sales	**(1.4)**	(12.1)
Income from unconsolidated affiliates	**(5.5)**	(3.0)
Distributions from unconsolidated affiliates and other	**7.8**	2.2
Loss on early extinguishment of debt	**0.7**	13.3
Unrealized gain on basis-only swaps	**(117.7)**	(121.7)
Changes in operating assets and liabilities		
Accounts receivable	**(144.6)**	(32.6)
Inventories	**(22.0)**	10.1
Prepaid expenses	**1.6**	(16.2)
Accounts payable and accrued expenses	**127.8**	4.2
Federal income taxes	**17.0**	(30.9)
Other	**(8.5)**	(7.5)
Net Cash Provided by Operating Activities of Continuing Operations	**1,292.6**	997.5
INVESTING ACTIVITIES		
Property acquisitions	**(48.0)**	(109.3)
Property, plant and equipment, including dry exploratory well expense	**(1,383.1)**	(1,359.7)
Proceeds from disposition of assets	**8.2**	25.6
Change in notes receivable	**-**	52.9
Net Cash Used in Investing Activities of Continuing Operations	**(1,422.9)**	(1,390.5)
FINANCING ACTIVITIES		
Checks outstanding in excess of cash balances	**9.9**	19.5
Long-term debt issued	**591.5**	1,034.4
Long-term debt issuance costs paid	**(10.6)**	(16.6)
Current portion long-term debt repaid	**(58.5)**	(91.5)
Repayments of notes payable	**-**	(39.3)
Long-term debt repaid	**(385.0)**	(761.5)
Long-term debt extinguishment costs	**-**	(4.9)

Other capital contributions	**2.3**	2.8
Equity contribution	**-**	250.0
Dividends paid	**(14.1)**	(7.0)
Distribution from Questar	**0.2**	(7.2)
Distribution to noncontrolling interest	**(5.4)**	(5.0)
Net Cash Provided by Financing Activities of Continuing Operations	**130.3**	373.7
CASH PROVIDED BY (USED IN) CONTINUING OPERATIONS	**-**	(19.3)
Cash provided by operating activities of discontinued operations	**-**	68.6
Cash used in investing activities of discontinued operations	**-**	(39.9)
Cash used in financing activities of discontinued operations	**-**	(26.9)
Effect of change in cash and cash equivalents of discontinued operations	**-**	(1.8)
Change in cash and cash equivalents	**-**	(19.3)
Beginning cash and cash equivalents	**-**	19.3
Ending cash and cash equivalents	**$ -**	$ -
Supplemental Disclosure of Cash Paid (Received) During the Year for:		
Interest	**$ 93.5**	$ 83.3
Income taxes	**(28.5)**	14.0

QEP RESOURCES, INC.
OPERATIONS BY LINE OF BUSINESS
(Unaudited)

	Three Months Ended December 31,		Year Ended December 31,	
	2011	2010	**2011**	2010
	(in millions)			
Revenues from Unaffiliated customers (1)				
QEP Energy	**$ 625.9**	$ 387.2	**$ 2,213.2**	$ 1,456.3
QEP Field Services	**95.4**	63.3	**369.3**	245.5
QEP Marketing and other	**132.0**	137.4	**576.7**	598.8
Total	**$ 853.3**	$ 587.9	**$ 3,159.2**	$ 2,300.6
Operating income (loss)				
QEP Energy	**$ (56.7)**	$ 82.8	**$ 240.4**	$ 399.8
QEP Field Services	**71.2**	38.7	**259.2**	150.6
QEP Marketing and other	**2.0**	3.3	**6.3**	8.4
Separation costs	**-**	0.7	**-**	(13.5)
Total	**$ 16.5**	$ 125.5	**$ 505.9**	$ 545.3
Net income (loss) from continuing operations attributable to QEP				
QEP Energy	**$ (43.5)**	$ 38.9	**$ 104.7**	$ 203.9
QEP Field Services	**40.3**	22.6	**154.5**	91.1
QEP Marketing and other	**2.9**	3.1	**8.4**	6.7
Separation and debt extinguishment costs	**-**	0.4	**(0.4)**	(18.7)
Total	**$ (0.3)**	$ 65.0	**$ 267.2**	$ 283.0

(1) During the year ended December 31, 2011, QEP revised its reporting of transportation and handling costs. Transportation and handling costs have been recast on the Consolidated Income Statement from revenues to "Natural gas, oil and NGL transportation and other handling costs" for all periods presented.

	Three Months Ended December 31,		Year Ended December 31,	
	2011	2010	**2011**	2010
QEP Energy production volumes				
Natural gas (Bcf)	**60.5**	54.6	**236.4**	203.8
Oil (Mbbl)	**1,182.1**	830.3	**3,741.3**	2,979.8
NGL (Mbbl)	**1,040.6**	438.9	**2,715.6**	1,225.8
Total production (Bcfe)	**73.9**	62.1	**275.2**	229.0
Average daily production (MMcfe)	**803.3**	675.4	**753.9**	627.4
QEP Energy average net realized price				
Natural gas (per Mcf)	**$ 4.74**	$ 5.14	**$ 4.74**	$ 5.32
Oil (per bbl)	**87.56**	68.30	**86.63**	66.48
NGL (per bbl)	**56.34**	39.30	**47.76**	39.04

<u>**Production by major area**</u>

QEP Energy - Natural gas (Bcf)

	Three Months Ended December 31, 2011	Three Months Ended December 31, 2010	Year Ended December 31, 2011	Year Ended December 31, 2010
Haynesville/Cotton Valley	**26.5**	22.2	**107.1**	79.3
Midcontinent	**8.6**	7.9	**32.9**	30.8
Pinedale Anticline	**19.1**	17.6	**69.3**	65.1
Uinta Basin	**3.1**	3.7	**14.9**	14.9
Rockies Legacy	**3.2**	3.2	**12.2**	13.7
Total production	**60.5**	54.6	**236.4**	203.8
QEP Energy - Oil (Mbbl)				
Haynesville/Cotton Valley	**14.8**	16.6	**51.0**	78.4
Midcontinent	**295.2**	168.0	**835.3**	644.3
Pinedale Anticline	**164.8**	149.9	**583.8**	551.8
Uinta Basin	**209.4**	250.6	**866.7**	957.1
Rockies Legacy	**497.9**	245.2	**1,404.5**	748.2
Total production	**1,182.1**	830.3	**3,741.3**	2,979.8

	Three Months Ended December 31,		Year Ended December 31,	
	2011	2010	**2011**	2010
QEP Energy - NGL (Mbbl)				
Haynesville/Cotton Valley	**2.2**	2.4	**8.4**	5.5
Midcontinent	**364.3**	377.4	**1,371.2**	997.0
Pinedale Anticline	**610.6**	-	**1,099.6**	-
Uinta Basin	**23.3**	32.2	**106.4**	121.5
Rockies Legacy	**40.2**	26.9	**130.0**	101.8
Total production	**1,040.6**	438.9	**2,715.6**	1,225.8
QEP Energy - Total Production (Bcfe)				
Haynesville/Cotton Valley	**26.6**	22.4	**107.5**	79.8
Midcontinent	**12.7**	10.9	**46.2**	40.6
Pinedale Anticline	**23.8**	18.6	**79.4**	68.5
Uinta Basin	**4.6**	5.5	**20.8**	21.4
Rockies Legacy	**6.2**	4.7	**21.3**	18.7
Total production	**73.9**	62.1	**275.2**	229.0
QEP Field Services Operating Statistics				
Natural gas gathering volumes (millions of MMBtu)				
For unaffiliated customers	**67.8**	66.8	**261.2**	276.8
For affiliated customers	**60.6**	54.4	**234.2**	198.9
Total gathering	**128.4**	121.2	**495.4**	475.7
Gathering revenue (per MMBtu)	**$ 0.32**	$ 0.32	**$ 0.33**	$ 0.32
QEP Field Services Gathering Margin				
Gathering	**$ 41.1**	$ 39.2	**$ 161.1**	$ 152.5
Other Gathering	**9.3**	11.0	**68.5**	36.7
Gathering (expense)	**(9.3)**	(10.5)	**(44.6)**	(37.6)
Gathering Margin	**$ 41.1**	$ 39.7	**$ 185.0**	$ 151.6
QEP Field Services Processing Margin				
NGL sales	**$ 60.1**	$ 24.2	**$ 180.0**	$ 94.8
Processing (fee-based) revenues	**16.1**	9.0	**53.7**	35.2
Other processing fees	**0.5**	-	**2.2**	-
Processing (expense)	**(3.3)**	(3.1)	**(12.2)**	(11.9)
Processing plant fuel and shrinkage (expense)	**(15.1)**	(6.7)	**(49.2)**	(32.6)
Natural gas, oil and NGL transportation and other handling costs	**(4.7)**	-	**(9.3)**	-
Processing margin	**$ 53.6**	$ 23.4	**$ 165.2**	$ 85.5
Frac spread (NGL sales less processing plant fuel and shrinkage less natural gas, oil and NGL transportation and other handling costs)	**$ 40.3**	$ 17.5	**$ 121.5**	$ 62.2
Operating Statistics				
Natural gas processing volumes				
NGL sales (MMgal)	**43.6**	22.9	**141.8**	100.2
Average NGL sales price (per gal)	**$ 1.38**	$ 1.05	**$ 1.27**	$ 0.95
Fee-based processing volumes (in millions of MMBtu)				
For unaffiliated customers	**26.5**	28.9	**122.9**	116.8
For affiliated customers	**33.1**	28.9	**117.8**	109.4
Total fee-based processing volumes	**59.6**	57.8	**240.7**	226.2
Average fee-based processing revenue (per MMBtu)	**$ 0.27**	$ 0.15	**$ 0.22**	$ 0.16

QEP RESOURCES, INC.
NON-GAAP MEASURES
(Unaudited)

This release contains reference to a non-GAAP measure of earnings per diluted share from continuing operations excluding gains and losses from asset sales, asset impairments, unrealized gains and losses on basis-only swaps, separation costs and loss on early extinguishment of debt. Management believes earnings per diluted share excluding asset sales, asset impairments, unrealized basis-only swaps, separation costs and loss on early extinguishment of debt is an important measure of the Company's operational performance relative to other gas and oil producing companies.

The following table calculates earnings per diluted share excluding gains and losses on assets sales, unrealized gains and losses on basis-only swaps, separation costs and loss on early extinguishment of debt:

	Three Months Ended December 31,		Year Ended December 31,	
	2011	2010	**2011**	2010
	(in millions, except earnings per share)			
Net income (loss) attributable to QEP Resources	**$ (0.3)**	$ 65.0	**$ 267.2**	$ 326.2
Less: Discontinued operations	**-**	-	**-**	(43.2)
Net income (loss) from continuing operations attributable to QEP Resources	**(0.3)**	65.0	**267.2**	283.0
Exclusion of net (gain) loss from assets sales, unrealized (gain) loss on basis-only swaps, separation costs and loss on early extinguishment of debt from net income				
Net (gain) loss from asset sales	**-**	0.2	**(1.4)**	(12.1)
Income taxes on net (gain) loss on asset sales	**-**	(0.1)	**0.5**	4.5
Non-cash price-related impairment charge	**195.2**	-	**195.2**	-
Income taxes on non-cash price-related impairment charge	**(70.5)**	-	**(70.5)**	-
Unrealized (gain) loss on basis-only swaps	**(31.0)**	(31.7)	**(117.7)**	(121.7)
Income taxes on unrealized (gain) loss on basis-only swaps	**11.2**	11.8	**42.5**	45.4
Separation costs	**-**	(0.7)	**-**	13.5
Income taxes on separation costs	**-**	0.3	**-**	(3.0)
Loss from early extinguishment of debt	**-**	-	**0.7**	13.3
Income taxes on loss from early extinguishment of debt	**-**	-	**(0.3)**	(5.1)
After-tax (gain) loss from assets sales, unrealized (gain) loss on basis swap, separation costs and loss on early extinguishment of debt	**104.9**	(20.2)	**49.0**	(65.2)
Net income (loss) attributable to QEP Resources excluding (gain) loss from assets sales, unrealized (gain) loss on basis swap, separation costs and loss on early extinguishment of debt	**$ 104.6**	$ 44.8	**$ 316.2**	$ 217.8
EARNINGS PER COMMON SHARE FROM CONTINUING OPERATIONS ATTRIBUTABLE TO QEP RESOURCES				
Diluted	**$ -**	$0.37	**$1.50**	$1.60
Diluted after-tax (gain) loss from asset sales, unrealized (gain) loss on basis-only swaps, separation costs and loss on early extinguishment of debt	**0.58**	(0.12)	**0.27**	(0.37)
Earnings (loss) per diluted share from continuing operations attributable to QEP Resources excluding asset sales, unrealized (gain) loss on basis only swaps, separation costs and loss on early extinguishment of debt	**$ 0.58**	$0.25	**$1.77**	$1.23
Weighted-Average Common Shares Outstanding				
Diluted	**178.2**	177.4	**178.4**	177.3

This release also contains reference to a non-GAAP measure of Adjusted EBITDA. Management defines Adjusted EBITDA as net income before the following items: discontinued operations, unrealized gains and losses on basis-only swaps, gains and losses from asset sales, interest and other income, income taxes, interest expense, separation costs, loss on early extinguishment of debt, depreciation, depletion, and amortization, abandonment and impairment, and exploration expense. Management uses Adjusted EBITDA to assess the Company's operating results. Management believes Adjusted EBITDA is an important measure of the Company's cash flow and liquidity, its ability to incur and service debt, fund capital expenditures and make distributions to shareholders and is an important measure for comparing the Company's financial performance to other gas and oil producing companies. In addition, Adjusted EBITDA is a part of the Company's debt covenants as defined in its revolving credit agreement.

The following table reconciles QEP Resources' net income to Adjusted EBITDA:

	Three Months Ended December 31,		Year Ended December 31,	
	2011	2010	**2011**	2010
	(in millions)			
Net income (loss) attributable to QEP Resources	**$ (0.3)**	$ 65.0	**$ 267.2**	$ 326.2
Net income attributable to noncontrolling interest	**1.0**	0.8	**3.2**	2.9
Net income	**0.7**	65.8	**270.4**	329.1
Discontinued operations, net of tax	**-**	-	**-**	(43.2)

Income from continuing operations	**0.7**	65.8	**270.4**	285.9
Unrealized (gain) loss on basis-only swaps	**(31.0)**	(31.7)	**(117.7)**	(121.7)
Net (gain) loss from asset sales	**-**	0.2	**(1.4)**	(12.1)
Interest and other income	**(4.6)**	2.1	**(4.1)**	(2.3)
Income taxes	**(1.6)**	36.5	**154.4**	167.0
Interest expense	**23.0**	21.6	**90.0**	84.4
Separation costs	**-**	(0.7)	**-**	13.5
Loss on early extinguishment of debt	**-**	-	**0.7**	13.3
Depreciation, depletion and amortization	**199.0**	173.9	**765.4**	643.4
Abandonment and impairment	**202.0**	17.0	**218.4**	46.1
Exploration	**3.0**	13.8	**10.5**	23.0
EBITDA	**$ 390.5**	$ 298.5	**$ 1,386.6**	$ 1,140.5

SOURCE QEP Resources, Inc.

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