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NEWS RELEASE

SOUTHWESTERN ENERGY ANNOUNCES RECORD 2011 FINANCIAL AND OPERATING RESULTS AND REVISES 2012 CAPITAL INVESTMENTS PROGRAM

Houston, Texas – February 27, 2012...Southwestern Energy Company (NYSE: SWN) today announced its financial and operating results for the fourth quarter and the year ended December 31, 2011. Calendar year 2011 highlights include:

- Gas and oil production of 500 Bcfe, up 24% over 2010
- Proved oil and gas reserves of 5,893 Bcfe, up 19% over 2010
- Net income of $637.8 million, up 6% from 2010
- Net cash provided by operating activities before changes in operating assets and liabilities (a non-GAAP measure reconciled below) of approximately $1.8 billion, up 12% from 2010
- Finding and development costs of $1.31 per Mcfe
- Reserve replacement of 299%

“We proved again in 2011 that focusing on every aspect of the business with the right gas assets can yield outstanding results, even as gas prices dropped. I want to thank all of our employees for the progress we made in 2011,” remarked Steve Mueller, President and Chief Executive Officer of Southwestern Energy.

“2012 has already brought new challenges and we have modified our capital investments program and production guidance downward for 2012. A low cost structure, strong balance sheet, razor-sharp financial discipline and nimbleness to respond in this rapidly changing environment will still be the keys to success. In addition, our New Ventures ideas will begin blooming in 2012 and provide the potential for 2012 to be one of the most exciting years ever at Southwestern Energy. We are looking forward to creating additional value for our company and our stakeholders in 2012.”

Fourth Quarter of 2011 Financial Results

For the fourth quarter of 2011, Southwestern reported net income of $158.5 million, or $0.45 per diluted share, compared to $149.5 million, or $0.43 per diluted share, for the same period in 2010. The increase was primarily due to a 20% increase in production which was partially offset by lower realized natural gas prices and increased operating costs and expenses associated with higher production. Net cash provided by operating activities before changes in operating assets and liabilities (a non-GAAP measure reconciled below), was $453.7 million in the fourth quarter of 2011, compared to $395.1 million in the same period in 2010.

E&P Segment – Operating income from the company's E&P segment was $195.8 million for the fourth quarter of 2011, compared to $199.9 million for the same period in 2010. The slight decrease in operating income was primarily due to lower realized natural gas prices and increased operating costs and expenses associated with higher production, partially offset by higher natural gas production volumes.

Gas and oil production totaled 133.3 Bcfe in the fourth quarter of 2011, up 20% from 111.4 Bcfe in the fourth quarter of 2010, and included 116.5 Bcf from the company's Fayetteville Shale play, up from 98.7 Bcf in the fourth quarter of 2010. Production from the Marcellus Shale was 8.1 Bcf in the fourth quarter of 2011, compared to 0.8 Bcf in the fourth quarter of 2010.

Including the effect of hedges, Southwestern's average realized gas price in the fourth quarter of 2011 was $4.04 per Mcf, down from $4.33 per Mcf in the fourth quarter of 2010. The company's commodity hedging activities increased its average gas price by $1.00 per Mcf during the fourth quarter of 2011, compared to an increase of $0.93 per Mcf during the same period in 2010. As of February 27, 2012, the company had approximately 266 Bcf of its 2012 forecasted gas production hedged at an average floor price of $5.16 per Mcf and approximately 185 Bcf of its 2013 forecasted gas production hedged at an average floor price of $5.06 per Mcf.

The company typically sells its natural gas at a discount to NYMEX settlement prices. This discount includes a basis differential, third-party transportation charges and fuel charges. Disregarding the impact of commodity price hedges, the company's average price received for its gas production during the fourth quarter of 2011 was approximately $0.51 per Mcf lower than average NYMEX settlement prices, compared to approximately $0.40 per Mcf lower during the fourth quarter of 2010.

Lease operating expenses per unit of production for the company's E&P segment were $0.84 per Mcfe in both the fourth quarters of 2011 and 2010.

General and administrative expenses per unit of production were $0.29 per Mcfe in the fourth quarter of 2011, down from $0.31 per Mcfe in the fourth quarter of 2010. The decrease was primarily due to the effects of the company's increased production volumes which more than offset increased payroll, incentive compensation and employee-related costs associated with the expansion of its E&P operations due to the continued development of the Fayetteville Shale and Marcellus Shale areas.

Taxes other than income taxes per unit of production were $0.10 per Mcfe in the fourth quarter of 2011, compared to $0.09 per Mcfe in the fourth quarter of 2010. Taxes other than income taxes per Mcfe vary from period to period due to changes in severance and ad valorem taxes that result from the mix of the company's production volumes and fluctuations in commodity prices.

The company's full cost pool amortization rate decreased to $1.31 per Mcfe in the fourth quarter of 2011, compared to $1.32 per Mcfe in the fourth quarter of 2010. The decline in the average amortization rate was primarily the result of lower finding and development costs, combined with the sale of certain East Texas oil and natural gas leases and wells in the second quarter of 2011, as the proceeds from the sale were appropriately credited to the full cost pool. The amortization rate is impacted by the timing and amount of reserve additions and the costs associated with those additions, revisions of previous reserve estimates due to both price and well performance, write-downs that result from full cost ceiling tests, proceeds from the sale of properties that reduce the full cost pool and the levels of costs subject to amortization.

Midstream Services – Operating income for the company's Midstream Services segment, which is comprised of natural gas gathering and marketing activities, was $67.6 million for the three months ended December 31, 2011, up from $56.8 million in the same period in 2010. The increase in operating income was primarily due to the increase in gathering revenues from the company's Fayetteville and Marcellus Shale properties, partially offset by increased operating costs and expenses.

Full-Year 2011 Financial Results

Southwestern reported net income of $637.8 million in 2011, or $1.82 per diluted share, up 6% from $604.1 million, or $1.73 per diluted share, in 2010. Net cash provided by operating activities before changes in operating assets and liabilities (a non-GAAP measure reconciled below), was approximately $1.8 billion in 2011, up 12% from approximately $1.6 billion in 2010.

E&P Segment – Operating income from the company's E&P segment was $825.1 million in 2011, compared to $829.5 million in 2010. The slight decrease in operating income was primarily due to lower realized natural gas prices and increased operating costs and expenses associated with higher production, offset by higher natural gas production volumes.

Gas and oil production was 500.0 Bcfe in 2011, up 24% compared to 404.7 Bcfe in 2010, and included 436.8 Bcf from the company's Fayetteville Shale play, up from 350.2 Bcf in 2010. Production from the Marcellus Shale was 23.4 Bcf in 2011, compared to 1.0 Bcf in 2010.

Southwestern's average realized gas price was $4.19 per Mcf, including the effect of hedges, in 2011 compared to $4.64 per Mcf in 2010. The company's hedging activities increased the average gas price realized in 2011 by $0.63 per Mcf, compared to an increase of $0.71 per Mcf in 2010. Disregarding the impact of hedges, the average price received for the company's gas production during 2011 was approximately $0.48 per Mcf lower than average NYMEX settlement prices, compared to approximately $0.46 per Mcf lower than NYMEX settlement prices in 2010. At December 31, 2011, Southwestern had basis protected on approximately 269.4 Bcf of its 2012 expected natural gas production through financial hedging activities and physical sales arrangements at a basis differential to NYMEX gas prices of approximately $0.02 per Mcf. For 2012, the company expects its total gas sales discount to NYMEX to be $0.45 to $0.55 per Mcf.

Lease operating expenses for the company's E&P segment were $0.84 per Mcfe in 2011, up from $0.83 per Mcfe in 2010. The increase was primarily due to increased gathering costs in the company's Fayetteville Shale operations.

General and administrative expenses were $0.27 per Mcfe in 2011, down from $0.30 per Mcfe in 2010. The decrease was primarily due to the effects of the company's increased production volumes which more than offset increased payroll, incentive compensation and employee-related costs associated with the expansion of its E&P operations due to the continued development of the Fayetteville Shale and Marcellus Shale areas.

Taxes other than income taxes were $0.11 per Mcfe in both 2011 and 2010.

The company's full cost pool amortization rate decreased to $1.30 per Mcfe in 2011, compared to $1.34 per Mcfe in 2010, primarily due to lower finding and development costs and the sale of certain East Texas properties in 2011 and 2010.

Midstream Services – Operating income for the company's midstream activities was $248.0 million in 2011, up 29% compared to $191.6 million in 2010. The increase in operating income was primarily due to increased gathering revenues related to the company's Fayetteville and Marcellus Shale properties, partially offset by increased operating costs and expenses. At December 31, 2011, the company's midstream segment was gathering approximately 2.1 Bcf per day through 1,791 miles of gathering lines in the Fayetteville Shale play, compared to gathering approximately 1.8 Bcf per day through 1,569 miles of gathering lines at December 31, 2010. Gathering volumes, revenues and expenses for this segment are expected to grow over the next few years largely as a result of increased development of the company's acreage in the Fayetteville Shale and Marcellus Shale and the increased development activity undertaken by other operators in those areas.

Capital Structure and Investments – At December 31, 2011, the company had approximately $1.3 billion in long-term debt and its long-term debt-to-total capitalization ratio had declined to 25.3%, down from 27.0% at December 31, 2010.

In 2011, Southwestern invested approximately $2.2 billion, up from approximately $2.1 billion in capital investments in 2010, and included approximately $2.0 billion invested in its E&P business, $161 million invested in its Midstream Services segment and $69 million invested for corporate and other purposes.

Revised 2012 Capital Program and Production Guidance

The company currently expects that its total capital investments for the full year of 2012 to be approximately $2.1 billion, down from its original estimate in December 2011 of $2.3 billion. The following table provides the company's forecast information for 2012, as compared to 2011 results, for capital investments.

	Capital Investments	
	Actual 2011	**Forecast 2012**
	(in millions)	
Fayetteville Shale	$ 1,347	$ 1,100
Marcellus Shale	332	526
New Ventures	201	177
Ark-La-Tex	76	18
Midstream Services	161	193
Corporate, E&P Services & Other	90	91
Total Capital Investments	**$ 2,207**	**$ 2,105**

The company has also updated its production guidance for 2012 due to the reduction in its previous planned capital investments. The revised total gas and oil production guidance for 2012 of 560 to 570 Bcfe is an increase of approximately 13% over the company's 2011 gas and oil production (using midpoints). Of the company's total expected production in 2012, approximately 465 to 470 Bcf is expected to come from the Fayetteville Shale and approximately 60 to 65 Bcf is expected to come from the Marcellus Shale. The company's production guidance for the 2012 as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Full-Year 2012
Previous (Bcfe)	134 - 136	138 - 140	145 - 148	153 - 156	570 - 580
Revised (Bcfe)	132 - 134	136 - 138	142 - 145	150 - 153	560 - 570

Southwestern Reports Record Gas and Oil Reserves

Southwestern's estimated proved gas and oil reserves totaled 5,893 Bcfe at December 31, 2011, up 19% from 4,937 Bcfe at the end of 2010. Approximately 100% of the company's year-end 2011 and year-end 2010 estimated proved reserves were natural gas and 55% were classified as proved developed, respectively.

The following table details additional information relating to reserve estimates as of and for the year ended December 31, 2011:

	Natural Gas (Bcf)	Crude Oil (MMBbls)	Total (Bcfe)
Proved Reserves, Beginning of Year	4,930.0	1.2	**4,937.3**
Revisions of Previous Estimates	34.5	(0.1)	**33.7**
Extensions, Discoveries, & Other Additions	1,459.4	----	**1,459.4**
Production	(499.4)	(0.1)	**(500.0)**
Acquisition of Reserves in Place	----	----	----
Disposition of Reserves in Place	(37.3)	----	**(37.3)**
Proved Reserves, End of Year	5,887.2	1.0	**5,893.2**
Proved, Developed Reserves:			
Beginning of Year	2,687.2	1.2	**2,694.3**

End of Year	3,254.0	1.0	**3,259.9**

Note: Figures may not add due to rounding

In 2011, Southwestern replaced 299% of its production volumes with an increase of 1,459.4 Bcfe of proved gas and oil reserves as a result of its drilling program and net upward revisions of 33.7 Bcfe. Of the reserve additions, 611.6 Bcfe were proved developed and 847.8 Bcfe were proved undeveloped. The upward reserve revisions during 2011 were primarily due to 42.9 Bcfe in upward revisions related to improved well performance offset by downward revisions of 9.2 Bcfe due to a comparative decrease in the average gas price for 2011 as compared to 2010. In addition, the company's reserves decreased by 37.3 Bcfe as a result of the sale of certain oil and natural gas leases and wells in 2011. For the period ending December 31, 2011, the company's three-year average reserve replacement ratio, including revisions, was 416%. Excluding reserve revisions, the company's 2011 and three-year average reserve replacement ratios were 292% and 380%, respectively.

Southwestern's all-in finding and development cost was $1.31 per Mcfe in 2011, including reserve revisions, compared to $1.02 per Mcfe in 2010. For the period ending December 31, 2011, the company's three-year finding and development cost, including revisions, was $1.05 per Mcfe. Excluding reserve revisions, the company's 2011 and three-year average finding and development costs were $1.34 per Mcfe and $1.15 per Mcfe, respectively (a non-GAAP financial measure computed below).

The following table provides an overall and by category summary of the company's gas and oil reserves, as of fiscal year end 2011 based on average fiscal year prices, and its well count, net acreage and PV-10 as of December 31, 2011 and sets forth 2011 annual information related to production and capital investments for each of its operating areas:

2011 Proved Reserves by Category and Summary Operating Data

			Ark-La-Tex			
	Fayetteville Shale	**Marcellus Shale**	**East Texas**	**Arkoma Basin**	**New Ventures**	**Total**
Estimated Proved Reserves:						
Natural Gas (Bcf):						
Developed (Bcf)	2,689	172	220	173	-	**3,254**
Undeveloped (Bcf)	2,415	170	27	21	-	**2,633**
	5,104	342	247	194	-	**5,887**
Crude Oil (MMBbls):						
Developed (MMBbls)	-	-	1	-	-	**1**
Undeveloped (MMBbls)	-	-	-	-	-	**-**
	-	-	1	-	-	**1**
Total Proved Reserves (Bcfe)[(1)]:						
Proved Developed (Bcfe)	2,689	172	226	173	-	**3,260**
Proved Undeveloped (Bcfe)	2,415	170	27	21	-	**2,633**
	5,104	342	253	194	-	**5,893**
Percent of Total	87%	6%	4%	3%	-	**100%**
Percent Proved Developed	53%	50%	89%	89%	-	**55%**
Percent Proved Undeveloped	47%	50%	11%	11%	-	**45%**
Production (Bcfe)	436.8	23.4	23.5	16.3	-	**500.0**
Capital Investments (millions)[(2)]	$ 1,347	$ 332	$ 68	$ 8	$ 201	**$ 1,956**

Total Gross Producing Wells	2,735	30	602	1,185	-	**4,552**
Total Net Producing Wells	1,856	22	459	574	-	**2,911**
Total Net Acreage	800,786[(3)]	186,893[(4)]	91,082[(5)]	319,550[(6)]	3,600,314[(7)]	**4,998,625**
Net Undeveloped Acreage	360,473[(3)]	180,676[(4)]	27,281[(5)]	138,191[(6)]	3,600,314[(7)]	**4,306,935**
PV-10:						
Pre-tax (millions)[(8)]	$ 3,806	$ 511	$ 260	$ 226	$ -	**$ 4,803**
PV of taxes (millions)[(8)]	1,071	144	73	64	-	**1,352**
After-tax (millions)[(8)]	$ 2,735	$ 367	$ 187	$ 162	$ -	**$ 3,451**
Percent of Total	79%	11%	5%	5%	-	**100%**
Percent Operated[(9)]	96%	99%	98%	87%	-	**96%**

(1) The company has no reserves from synthetic gas, synthetic oil or nonrenewable natural resources intended to be upgraded into synthetic gas or oil. Southwestern's proved reserves increased by 1,459.4 Bcfe as a result of its drilling program and net upward revisions of 33.7 Bcfe in 2011. Of the reserve additions, 611.6 Bcfe were proved developed and 847.8 Bcfe were proved undeveloped. The company used standard engineering and geoscience methods, or a combination of methodologies in determining estimates of material properties, including performance and test date analysis offset statistical analogy of performance data, volumetric evaluation, including analysis of petrophysical parameters (including porosity, net pay, fluid saturations (i.e., water, oil and gas) and permeability) in combination with estimated reservoir parameters (including reservoir temperature and pressure, formation depth and formation volume factors), geological analysis, including structure and isopach maps and seismic analysis, including review of 2-D and 3-D data to ascertain faults, closure and other factors.

(2) The company's Total and Fayetteville Shale play capital investments exclude $21 million related to its drilling rig related equipment, sand facility and other equipment.

(3) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 2,804 net acres in 2012, 208,563 net acres in 2013, which includes 184,696 net acres held on federal lands, and 23,800 net acres in 2014.

(4) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 58,210 net acres in 2012, 44,551 net acres in 2013 and 10,071 net acres in 2014.

(5) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 380 net acres in 2012, 790 net acres in 2013 and 77 net acres in 2014.

(6) Includes 123,442 net developed acres and 1,614 net undeveloped acres in the Arkoma Basin that are also within the company's Fayetteville Shale focus area but not included in the Fayetteville Shale acreage in the table above. Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 30,025 net acres in 2012, 2,181 net acres in 2013 and 31,769 net acres in 2014.

(7) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years, excluding New Brunswick, Canada and the Lower Smackover Brown Dense (LSBD) area will be 1,200 net acres in 2012, 1,200 net acres in 2013 and 31,600 net acres in 2014. With regard to the company's acreage in New Brunswick, Canada, assuming the options are not extended/exercised by March 2013 then, in such event, 2,518,518 net acres will expire in 2013. With regard to the LSBD acreage, assuming successful wells are not drilled and leases are not extended, leasehold expiring over the next three years will be 15,860 net acres in 2012, 64,120 net acres in 2013 and 228,660 net acres in 2014.

(8) Pre-tax PV-10 (a non-GAAP measure) is one measure of the value of a company's proved reserves that the company believes is used by securities analysts to compare relative values among peer companies without regard to income taxes. The reconciling difference in pre-tax PV-10 and the after-tax PV-10, or standardized measure, is the discounted value of future income taxes on the estimated cash flows from our proved oil and natural gas reserves.

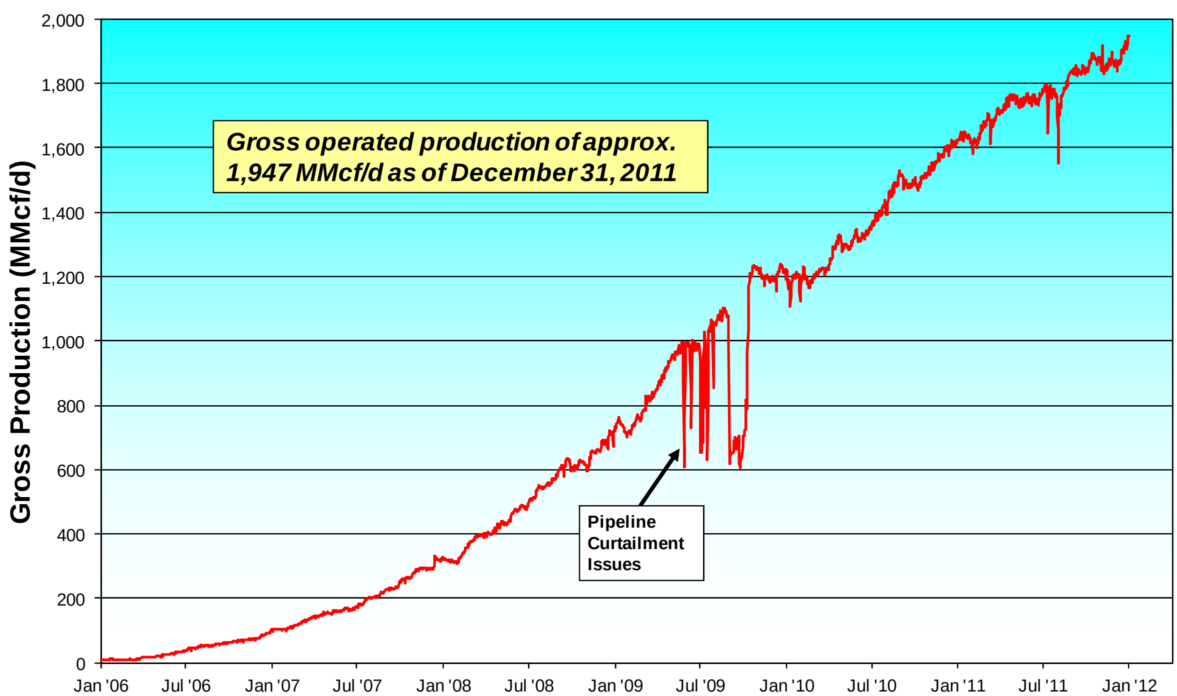
(9) Based upon pre-tax PV-10 of proved developed producing properties.

2011 E&P Operations Review

During 2011, Southwestern invested a total of $2.0 billion in its E&P business and participated in drilling 708 wells, 447 of which were successful, and 261 which were in progress at year-end. Of the 261 wells in progress at year-end, 214 were located in the company's Fayetteville Shale play. Of the $2.0 billion invested in 2011, approximately $1.5 billion was invested in exploratory and development drilling and workovers, $227 million for acquisition of properties, $30 million for seismic expenditures and $199 million in capitalized interest and other expenses. Additionally, the company invested approximately $21 million in its drilling rig related equipment, sand facility and other equipment.

Fayetteville Shale – In 2011, Southwestern invested approximately $1.3 billion in its Fayetteville Shale play, which included approximately $1.2 billion to spud 650 wells, 580 of which were operated. The company increased its reserves in the Fayetteville Shale by 1.2 Tcf at a finding and development cost of $1.13 per Mcf (finding and development costs are considered by the SEC to be non-GAAP financial measures and have been computed below), including net downward reserve revisions of 15.3 Bcf due primarily to downward performance revisions of 14.1 Bcf and downward price revisions of 1.2 Bcf. Included in the company's total capital investments in the area during 2011 was $132 million in capitalized costs and other expenses and $10 million for the acquisition of properties.

Southwestern's net production from the Fayetteville Shale was 436.8 Bcf in 2011, up 25% from 350.2 Bcf in 2010, as gross production from the company's operated wells in the Fayetteville Shale increased from approximately 1,635 MMcf per day at the beginning of 2011 to approximately 1,947 MMcf per day by year-end. The graph below provides gross production data from the company's operated wells in the Fayetteville Shale area through December 31, 2011.



The company's total proved net reserves booked in the Fayetteville Shale at year-end 2011 were 5,104 Bcf from a total of 4,376 locations, of which 2,735 were proved developed producing, 59 were proved developed non-producing and 1,582 were proved undeveloped. Of the 4,376 locations, 4,310 were horizontal. The average gross proved reserves for the undeveloped wells included in its 2011 and 2010 year-end reserves was approximately 2.4 Bcf per well, respectively. Total proved net gas reserves booked in the area at year-end 2010 totaled approximately 4,345 Bcf from a total of 3,682 locations, of which 2,120 were proved developed producing, 36 were proved developed non-producing and 1,526 were proved undeveloped.

Over the past several years, the company has seen continual improvement in its drilling practices in the Fayetteville Shale play. Southwestern's operated horizontal wells had an average completed well cost of $2.8 million per well, average horizontal lateral length of 4,836 feet and average time to drill to total depth of 8 days from re-entry to re-entry in 2011. This compares to an average completed operated well cost of $2.8 million per well, average horizontal lateral length of 4,528 feet and average time to drill to total depth of 11 days from re-entry to re-entry during 2010. The operated wells the company placed on production during 2011 averaged initial production rates of 3,330 Mcf per day, compared to average initial production rates of 3,364 Mcf per day in 2010. The slight decrease in initial production rates was primarily due to increased well density and locational differences in the mix of wells. During 2011, Southwestern placed 51 operated wells on production with initial production rates that exceeded 5.0 MMcf per day, including 6 wells that exceeded 6.0 MMcf per day.

During the fourth quarter of 2011, the company's horizontal wells had an average completed well cost of $2.8 million per well, average horizontal lateral length of 4,703 feet and average time to drill to total depth of 7.3 days from re-entry to re-entry. This compares to an average completed well cost of $2.8 million per well, average horizontal lateral length of 4,847 feet and average time to drill to total depth of 7.8 days from re-entry to re-entry in the third quarter of 2011. In the fourth quarter of 2011, the company had 24 operated wells placed on production which had average times to drill to total depth of 5 days or less from re-entry to re-entry. In total, the company has had a total of 104 wells drilled to total depth of 5 days or less from re-entry to re-entry.

The company's wells placed on production during the fourth quarter of 2011 averaged initial production rates of 3,646 Mcf per day. Results from the company's drilling activities from 2007 by quarter are shown below.

Time Frame	**Wells Placed on Production**	**Average IP Rate (Mcf/d)**	**30th-Day Avg Rate (# of wells)**	**60th-Day Avg Rate (# of wells)**	**Average Lateral Length**
1st Qtr 2007	58	1,261	1,066 (58)	958 (58)	2,104
2nd Qtr 2007	46	1,497	1,254 (46)	1,034 (46)	2,512
3rd Qtr 2007	74	1,769	1,510 (72)	1,334 (72)	2,622
4th Qtr 2007	77	2,027	1,690 (77)	1,481 (77)	3,193
1st Qtr 2008	75	2,343	2,147 (75)	1,943 (74)	3,301
2nd Qtr 2008	83	2,541	2,155 (83)	1,886 (83)	3,562
3rd Qtr 2008	97	2,882	2,560 (97)	2,349 (97)	3,736
4th Qtr 2008(1)	74	3,350(1)	2,722 (74)	2,386 (74)	3,850
1st Qtr 2009(1)	120	2,992(1)	2,537 (120)	2,293 (120)	3,874
2nd Qtr 2009	111	3,611	2,833 (111)	2,556 (111)	4,123
3rd Qtr 2009	93	3,604	2,624 (93)	2,255 (93)	4,100
4th Qtr 2009	122	3,727	2,674 (122)	2,360 (120)	4,303
1st Qtr 2010(2)	106	3,197(2)	2,388 (106)	2,123 (106)	4,348
2nd Qtr 2010	143	3,449	2,554 (143)	2,321 (142)	4,532
3rd Qtr 2010	145	3,281	2,448 (145)	2,202 (144)	4,503
4th Qtr 2010	159	3,472	2,678 (159)	2,294 (159)	4,667
1st Qtr 2011	137	3,231	2,604 (137)	2,238(137)	4,985

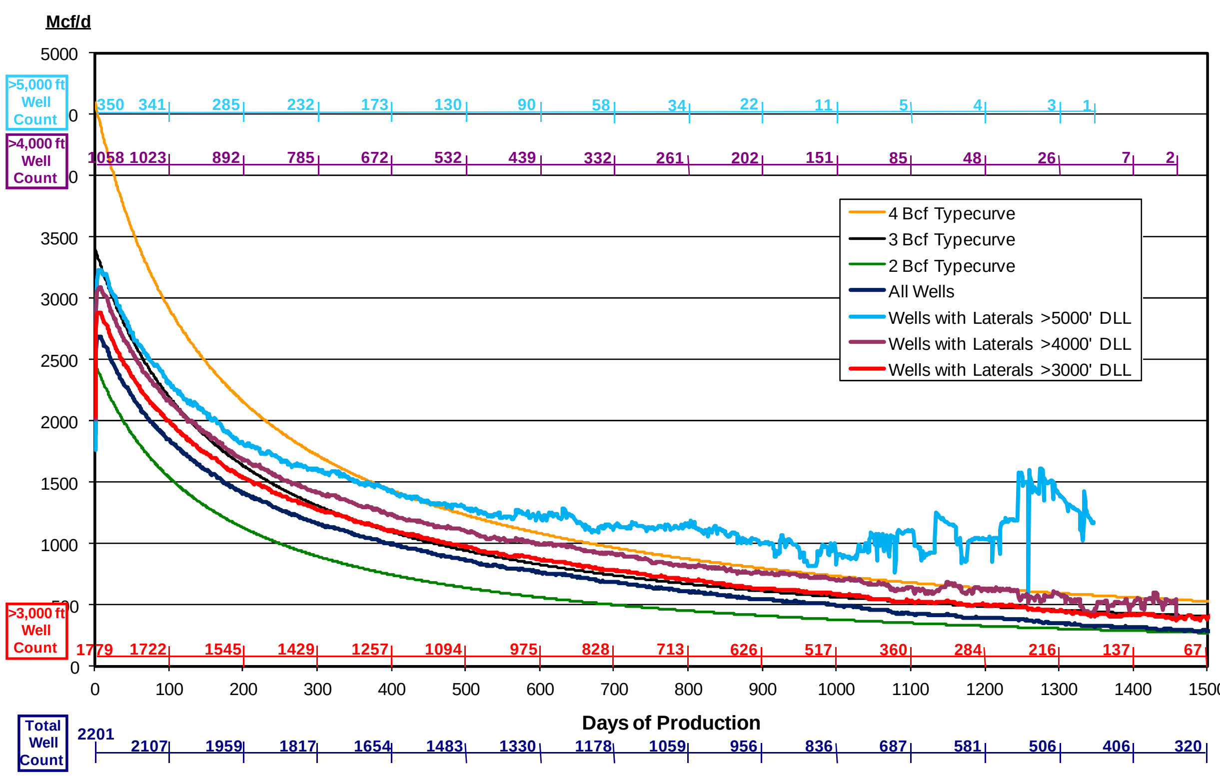
2nd Qtr 2011	149	3,014	2,328 (149)	1,991 (149)	4,839
3rd Qtr 2011	132	3,443	2,666 (132)	2,372 (132)	4,847
4th Qtr 2011	142	3,646	2,606 (142)	2,183 (105)	4,703

Note: Results as of December 31, 2011.

(1) The significant increase in the average initial production rate for the fourth quarter of 2008 and the subsequent decrease for the first quarter of 2009 primarily reflected the impact of the delay in the Boardwalk Pipeline.

(2) In the first quarter of 2010, the company's results were impacted by the shift of all wells to "green completions" and the mix of wells, as a large percentage of wells were placed on production in the shallower northern and far eastern borders of the company's acreage.

The graph below provides normalized average daily production data through December 31, 2011, for the company's horizontal wells using slickwater and crosslinked gel fluids. The "dark blue curve" is for horizontal wells fracture stimulated with either slickwater or crosslinked gel fluid. The "red curve" indicates results for the company's wells with lateral lengths greater than 3,000 feet, while the "purple curve" indicates results for the company's wells with lateral lengths greater than 4,000 feet and the "light blue curve" indicates results for the company's wells with lateral lengths greater than 5,000 feet. The normalized production curves are intended to provide a qualitative indication of the company's Fayetteville Shale wells' performance and should not be used to estimate an individual well's estimated ultimate recovery. The 2, 3 and 4 Bcf typecurves are shown solely for reference purposes and are not intended to be projections of the performance of the company's wells.



Notes: Data as of December 31, 2011. Excludes wells with mechanical problems (31).

At December 31, 2011, Southwestern held leases for approximately 925,842 net acres in the Fayetteville Shale area, compared to approximately 915,884 net acres at year-end 2010.

In 2012, Southwestern plans to invest approximately $1.1 billion in the Fayetteville Shale, $925 million of which will be directed toward drilling and completing approximately 460 to 470 gross horizontal wells (320 to 330 net wells), 425 to 435 of which will be operated by the company.

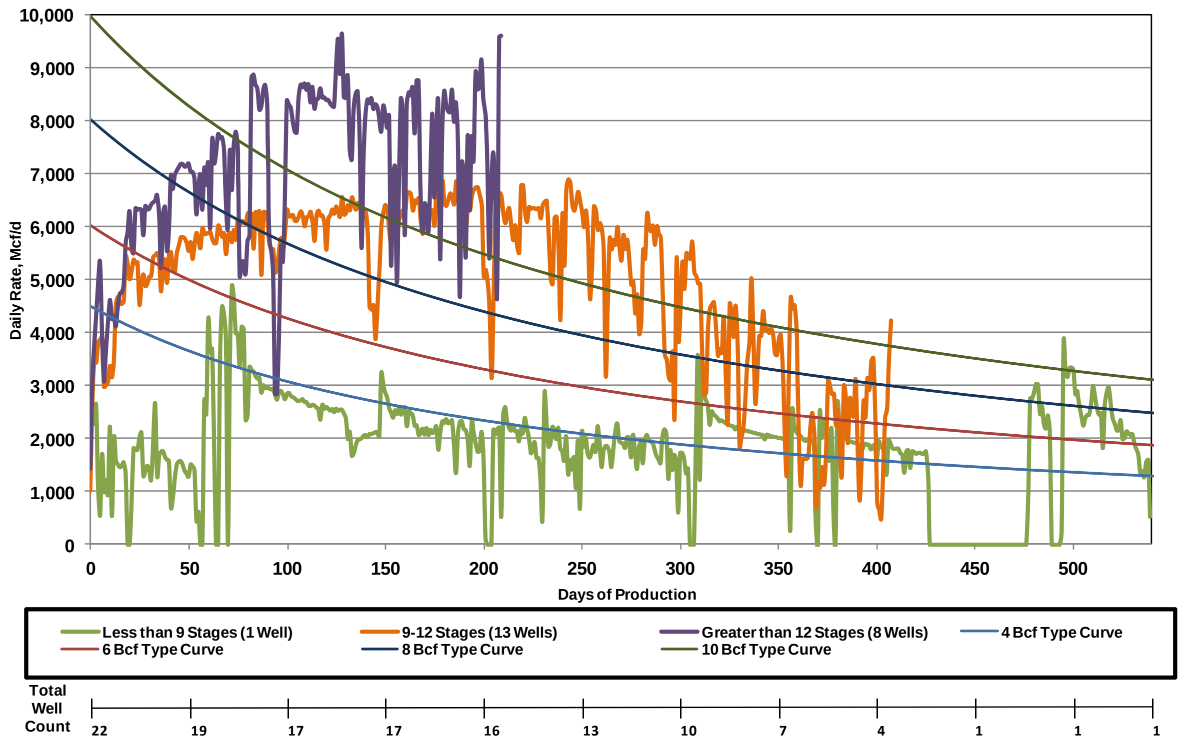
Marcellus Shale – In 2011, Southwestern invested approximately $332 million in the Marcellus Shale, which included approximately $214 million to participate in 45 wells. Of the 45 wells in which the company participated during 2011, 18 were horizontal wells located in Bradford County and the remaining 27 wells were located in Susquehanna County. The company added 327.3 Bcf of new reserves in the Marcellus Shale, including net upward reserve revisions of 98.1 Bcf due primarily to upward revisions of 102.6 Bcf from improved well performance offset by downward price revisions of 4.5 Bcf. Included in the company's total capital investments in the Marcellus Shale during 2011 was approximately $77 million for acquisition of leasehold properties, $13 million for seismic and $29 million in capitalized costs and other expenses. In 2010, Southwestern invested approximately $118 million in the Marcellus Shale and participated in 21 wells, adding new reserves of 38 Bcf.

As of year-end 2011, Southwestern had spud 70 wells, 23 of which were on production and 67 of which were horizontal wells, resulting in net production from this area of 23.4 Bcf in 2011, compared to 1.0 Bcf in 2010. At December 31, 2011, the company's gross operated production from the area was approximately 133 MMcf per day and limited by high line pressures.

Total proved net reserves from the company's Marcellus Shale area were 342 Bcf at year-end 2011 from a total of 60 locations, of which 30 were proved developed producing, 2 were proved developed non-producing and 28 were proved undeveloped. The average gross proved reserves for the undeveloped wells included in the company's year-end reserves was approximately 7.5 Bcf per well, up from 3.0 per well at year-end 2010.

At December 31, 2011, the company had 22 operated horizontal wells on production which had an average completed well cost of $6.4 million per well, average horizontal lateral length of 4,007 feet and an average of 12 fracture stimulation stages.

The graph below provides normalized average daily production data through December 31, 2011, for the company's horizontal wells in the Marcellus Shale. The "purple curve" indicates results for 8 wells with more than 12 fracture stimulation stages, the "orange curve" indicates results for 13 wells with 9 to 12 fracture stimulation stages and the "green curve" indicates results for 1 well with less than 9 fracture stimulation stages. The normalized production curves are intended to provide a qualitative indication of the company's Marcellus Shale wells' performance and should not be used to estimate an individual well's estimated ultimate recovery. The 4, 6, 8 and 10 Bcf typecurves are shown solely for reference purposes and are not intended to be projections of the performance of the company's wells.



Notes: Data as of December 31, 2011.

At December 31, 2011, Southwestern held leases for approximately 186,893 net acres in the Marcellus Shale area, compared to approximately 173,009 net acres at year-end 2010.

In 2012, Southwestern plans to invest approximately $526 million in the Marcellus Shale, $435 million of which will be directed toward drilling and completing approximately 80 to 85 gross horizontal wells (65 to 70 net wells), all of which will be operated by the company.

Ark-La-Tex – In 2011, Southwestern invested approximately $76 million in its Ark-La-Tex areas and participated in 10 wells, adding 19.0 Bcfe of new reserves which were offset by net downward reserve revisions of 49.2 Bcfe due primarily to downward performance revisions of 45.7 Bcfe and downward price revisions of 3.5 Bcfe. Total proved net reserves from the company's Ark-La-Tex areas were approximately 447 Bcfe at December 31, 2011, compared to 554 Bcfe at year-end 2010. Net production from these assets was 39.8 Bcfe in 2011, compared to 53.5 Bcfe in 2010. The decline in both reserves and production from these areas was primarily driven by asset dispositions in both 2011 and 2010, as well as natural field production declines and lower capital investments in these areas.

In 2012, the company expects to invest approximately $18 million in its Ark-La-Tex program.

New Ventures – As of December 31, 2011, Southwestern held 3,600,314 net undeveloped acres in connection with its New Ventures prospects, of which 2,518,518 net acres were located in New Brunswick, Canada. This compares to 3,009,643 net undeveloped acres held at year-end 2010, of which 2,518,518 net acres were located in New Brunswick, Canada.

Southwestern has 520,619 net acres targeting the Lower Smackover Brown Dense formation in southern Arkansas and northern Louisiana. This acreage was obtained at an average cost of $375 per acre and the company's leases currently have an 82% average net revenue interest and an average primary lease term of 4 years which may be extended for an additional 4 years. In February 2012, Southwestern completed its first well in the area, the Roberson 18-19 #1-15H located in Columbia County, Arkansas, at a total depth of approximately 9,369 feet and a horizontal lateral length of approximately 3,600 feet. The lateral was landed in the lower third of this zone and subsequent core analysis indicated this section had some of the lowest permeability in the entire interval. The well has been producing from 8 of 11 stages fractured stimulated for 20 days of an expected 20 to 30 day cleanup period. Oil production began on day 8 and the company is encouraged, with the highest 24-hour rates to date of 103 barrels of oil per day, 200 Mcf per day and 1,009 barrels of water per day (45% of load recovered to date). The company's second well, the Garrett 7-23-5H #1 located in Claiborne Parish, Louisiana, was drilled to a vertical depth in February 2012 at approximately 10,863 feet with a 6,536-foot horizontal lateral. Learning from the first well, this lateral was steered into the top of the interval, drilled faster and had better oil shows than the first well. The company has also spud its third well in February 2012, the BML #31-22 #1-1H located in Union Parish, Louisiana. If the company's drilling program yields positive results, it expects that activity in the play could increase significantly over the next several years.

The company has also announced it has leased 238,057 net acres in the Denver-Julesburg Basin in eastern Colorado where the company will begin testing a new unconventional oil play targeting middle and late Pennsylvanian to Permian age carbonates and shales. Common strata names include the Atoka, Desmoinsian-Cherokee-Excello-Tebo-Marmaton, Missourian, Virgilian, and Wolfcamp. The play objectives range in vertical depth from 8,000 to 10,500 feet and are within the oil window. The combined Wolfcamp-Atoka interval is over 1,500 feet thick. The primary objectives are alternating low permeable, 20 to 100 foot thick carbonates separated by 10 to 75 feet thick organic rich, carbonate mudstones with total organic carbon estimates ranging from 2% to 27%. Total thickness of the objective section ranges from 300 feet to 750 feet. This acreage was obtained for approximately $42 million and the company's leases currently have an 85% average net revenue interest and an average primary lease term of 5 years which may be extended for an additional 3 years. In February 2012, the company submitted a drilling plan to the Colorado Oil and Gas Conservation Commission for approval to spud its first well in the second quarter of 2012. This well will first be drilled 9,500 feet vertically, cored and then a 2,000-foot lateral will be drilled. If the company's drilling program yields positive results, it expects that activity in the area could increase significantly over the next several years.

In New Brunswick, Canada, the company has conducted airborne gravity and magnetics surveys and surface geochemistry surveys during 2011 and 2010 and, as of December 31, 2011, had acquired 248 miles of 2-D seismic data. While preliminary interpretation has already begun, in 2012 the company intends to continue its acquisition of approximately 130 additional miles of 2-D seismic data and plans to drill two stratigraphic well tests in the fourth quarter of 2012. Through December 31, 2011, the company has invested approximately $24.0 million in its New Brunswick exploration program.

In 2011, Southwestern invested $201 million in its New Ventures program and currently plans to invest approximately $177 million in New Ventures in 2012.

Explanation and Reconciliation of Non-GAAP Financial Measures

We report our financial results in accordance with accounting principles generally accepted in the United States of America ("GAAP"). However, management believes certain non-GAAP performance measures may provide users of this financial information with additional meaningful comparisons between current results and the results of our peers and of prior periods.

One such non-GAAP financial measure is net cash provided by operating activities before changes in operating assets and liabilities. Management presents this measure because (i) it is accepted as an indicator of an oil and gas exploration and production company's ability to internally fund exploration and development activities and to service or incur additional debt, (ii) changes in operating assets and liabilities relate to the timing of cash receipts and disbursements which the company may not control and (iii) changes in operating assets and liabilities may not relate to the period in which the operating activities occurred.

Additional non-GAAP financial measures we may present from time to time are net income attributable to Southwestern Energy, diluted earnings per share attributable to Southwestern Energy stockholders and our E&P segment operating income, all which exclude certain charges or amounts. Management presents these measures because (i) they are consistent with the manner in which the Company's performance is measured relative to the performance of its peers, (ii) these measures are more comparable to earnings estimates provided by securities analysts, and (iii) charges or amounts excluded cannot be reasonably estimated and guidance provided by the Company excludes information regarding these types of items. These adjusted amounts are not a measure of financial performance under GAAP.

See the reconciliations below of GAAP financial measures to non-GAAP financial measures for the three and twelve months ended December 31, 2011 and December 31, 2010. Non-GAAP financial measures should not be considered in isolation or as a substitute for the Company's reported results prepared in accordance with GAAP.

	3 Months Ended Dec. 31,	
	2011	2010
	(in thousands)	
Cash flow from operating activities:		
Net cash provided by operating activities	$ 439,606	$ 427,523
Add back (deduct):		
Change in operating assets and liabilities	14,072	(32,399)
Net cash provided by operating activities before changes in operating assets and liabilities	$ 453,678	$ 395,124

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	12 Months Ended Dec. 31,	
	2011	2010
	(in thousands)	
Cash flow from operating activities:		
Net cash provided by operating activities	$ 1,739,817	$ 1,642,585
Add back (deduct):		
Change in operating assets and liabilities	26,201	(62,906)
Net cash provided by operating activities before changes in operating assets and liabilities	$ 1,766,018	$ 1,579,679

Finding and development costs – Finding and development (F&D) costs are computed by dividing acquisition, exploration and development capital costs incurred for the indicated period by reserve additions, including reserves acquired, for that same period. The following computes F&D costs using information required by GAAP for the periods ending December 31, 2011 and December 31, 2010, and three years ending December 31, 2011.

	For the 12 Months Ending December 31, 2011	For the 12 Months Ending December 31, 2010	For the 3 Years Ending December 31, 2011	Fayetteville Shale Play 2011	Fayetteville Shale Play 2010
Total exploration, development and acquisition costs incurred ($ in thousands)	$ 1,960,106	$ 1,781,424	$ 5,271,406	$ 1,347,605	$ 1,351,535
Reserve extensions, discoveries and acquisitions (MMcfe)	1,459,456	1,431,125	4,575,772	1,211,210	1,305,609
Finding & development costs, excluding revisions ($/Mcfe)	$ 1.34	$ 1.24	$ 1.15	$ 1.11	$ 1.04
Reserve extensions, discoveries, acquisitions and reserve revisions (MMcfe)	1,493,201	1,740,717	5,011,963	1,196,041	1,578,722
Finding & development costs, including revisions ($/Mcfe)	$ 1.31	$ 1.02	$ 1.05	$ 1.13	$ 0.86

The company believes that providing a measure of F&D costs is useful for investors as a means of evaluating a company's cost to add proved reserves, on a per thousand cubic feet of natural gas equivalent basis. These measures are provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in Southwestern's financial statements prepared in accordance with GAAP (including the notes thereto). Due to various factors, including timing differences and the SEC's 2009 adoption of a number of revisions to its oil and gas reporting disclosure requirements, F&D costs do not necessarily reflect precisely the costs associated with particular reserves. For example, exploration costs may be recorded in periods prior to the periods in which related increases in reserves are recorded and development costs, including future development costs for proved undeveloped reserve additions, may be recorded in periods subsequent to the periods in which related increases in reserves are recorded. In addition, changes in commodity prices can affect the magnitude of recorded increases in reserves independent of the related costs of such increases. As a result of the foregoing factors and various factors that could materially affect the timing and amounts of future increases in reserves and the timing and amounts of future costs, including factors disclosed in Southwestern's filings with the SEC, future F&D costs may differ materially from those set forth above. Further, the methods used by Southwestern to calculate its F&D costs may differ significantly from methods used by other companies to compute similar measures and, as a result, Southwestern's F&D costs may not be comparable to similar measures provided by other companies.

Southwestern will host a teleconference call on Tuesday, February 28, 2012, at 10:00 a.m. Eastern to discuss the company's fourth quarter and year-end 2011 results. The toll-free number to call is 877-407-8035 and the international dial-in number is 201-689-

8035. The teleconference can also be heard "live" on the Internet at http://www.swn.com.

Southwestern Energy Company is an integrated company whose wholly-owned subsidiaries are engaged in oil and gas exploration and production, natural gas gathering and marketing. Additional information on the company can be found on the Internet at http://www.swn.com.

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All statements, other than historical facts and financial information, may be deemed to be forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements that address activities, outcomes and other matters that should or may occur in the future, including, without limitation, statements regarding the financial position, business strategy, production and reserve growth and other plans and objectives for the company's future operations, are forward-looking statements. Although the company believes the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance and actual results or developments may differ materially from those in the forward-looking statements. The company has no obligation and makes no undertaking to publicly update or revise any forward-looking statements, other than to the extent set forth below. You should not place undue reliance on forward-looking statements. They are subject to known and unknown risks, uncertainties and other factors that may affect the company's operations, markets, products, services and prices and cause its actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with forward-looking statements, risks, uncertainties and factors that could cause the company's actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to: the timing and extent of changes in market conditions and prices for natural gas and oil (including regional basis differentials); the company's ability to transport its production to the most favorable markets or at all; the timing and extent of the company's success in discovering, developing, producing and estimating reserves; the economic viability of, and the company's success in drilling, the company's large acreage position in the Fayetteville Shale play, overall as well as relative to other productive shale gas areas; the company's ability to fund the company's planned capital investments; the impact of federal, state and local government regulation, including any legislation relating to hydraulic fracturing, the climate or over the counter derivatives; the company's ability to determine the most effective and economic fracture stimulation for the Fayetteville Shale play and the Marcellus Shale play; the costs and availability of oil field personnel services and drilling supplies, raw materials, and equipment and services; the company's future property acquisition or divestiture activities; increased competition; the financial impact of accounting regulations and critical accounting policies; the comparative cost of alternative fuels; conditions in capital markets, changes in interest rates and the ability of the company's lenders to provide it with funds as agreed; credit risk relating to the risk of loss as a result of non-performance by the company's counterparties and any other factors listed in the reports the company has filed and may file with the Securities and Exchange Commission (SEC). For additional information with respect to certain of these and other factors, see the reports filed by the company with the SEC. The company disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

Financial Summary Follows

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OPERATING STATISTICS (Unaudited)
Southwestern Energy Company and Subsidiaries

	Three Months		Twelve Months	
Periods Ended December 31	**2011**	2010	**2011**	2010
Exploration & Production				
Production				
Natural gas production (Bcf)	**133.2**	111.2	**499.4**	403.6
Oil production (MBbls)	**18**	34	**97**	171
Total equivalent production (Bcfe)	**133.3**	111.4	**500.0**	404.7
Commodity Prices				
Average gas price per Mcf, including hedges	**$ 4.04**	$ 4.33	**$ 4.19**	$ 4.64
Average gas price per Mcf, excluding hedges	**$ 3.04**	$ 3.40	**$ 3.56**	$ 3.93
Average oil price per Bbl	**$ 96.49**	$ 82.70	**$ 94.08**	$ 76.84
Operating Expenses per Mcfe				
Lease operating expenses	**$ 0.84**	$ 0.84	**$ 0.84**	$ 0.83
General & administrative expenses	**$ 0.29**	$ 0.31	**$ 0.27**	$ 0.30
Taxes, other than income taxes	**$ 0.10**	$ 0.09	**$ 0.11**	$ 0.11
Full cost pool amortization	**$ 1.31**	$ 1.32	**$ 1.30**	$ 1.34
Midstream				
Gas volumes marketed (Bcf)	**161.0**	138.8	**611.4**	495.8
Gas volumes gathered (Bcf)	**200.0**	166.7	**745.7**	588.3

STATEMENTS OF OPERATIONS (Unaudited)

Southwestern Energy Company and Subsidiaries

	Three Months		Twelve Months	
Periods Ended December 31	**2011**	2010	**2011**	2010
	(in thousands, except share/per share amounts)			
Operating Revenues				
Gas sales	**$ 536,574**	$ 477,368	**$ 2,080,241**	$ 1,856,241
Gas marketing	**164,880**	154,337	**714,123**	615,913
Oil sales	**1,698**	2,791	**9,085**	13,111
Gas gathering	**42,012**	35,609	**149,973**	122,912
Other	**(1,014)**	326	**(516)**	2,486
	744,150	670,431	**2,952,906**	2,610,663
Operating Costs and Expenses				
Gas purchases – midstream services	**163,573**	153,606	**709,091**	611,161
Operating expenses	**65,181**	51,333	**240,944**	191,771
General and administrative expenses	**45,086**	40,828	**158,041**	145,563
Depreciation, depletion and amortization	**190,331**	156,025	**704,511**	590,332
Taxes, other than income taxes	**16,089**	11,954	**65,518**	50,608
	480,260	413,746	**1,878,105**	1,589,435
Operating Income (Loss)	**263,890**	256,685	**1,074,801**	1,021,228
Interest Expense				
Interest on debt	**17,041**	14,442	**65,421**	57,144
Other interest charges	**892**	488	**4,306**	1,935
Interest capitalized	**(13,121)**	(8,044)	**(45,652)**	(32,916)
	4,812	6,886	**24,075**	26,163
Other Income, Net	**(57)**	162	**264**	427
Income (Loss) Before Income Taxes	**259,021**	249,961	**1,050,990**	995,492
Provision (Benefit) for Income Taxes				
Current	**507**	14,513	**4,198**	11,939
Deferred	**99,981**	86,030	**409,023**	379,720
	100,488	100,543	**413,221**	391,659
Net income (loss)	**158,533**	149,418	**637,769**	603,833
Less: Net loss attributable to noncontrolling interest	**—**	(93)	**—**	(285)
Net Income (Loss) Attributable to Southwestern Energy	**$ 158,533**	$ 149,511	**$ 637,769**	$ 604,118
Earnings Per Share				
Net income (loss) attributable to Southwestern Energy stockholders - Basic	**$ 0.47**	$ 0.43	**$ 1.84**	$ 1.75
Net income (loss) attributable to Southwestern Energy stockholders - Diluted	**$ 0.45**	$ 0.43	**$ 1.82**	$ 1.73
Weighted Average Common Shares Outstanding				
Basic	**347,605,871**	346,337,014	**347,205,316**	345,581,568
Diluted	**350,048,857**	349,351,156	**349,921,413**	349,310,666

BALANCE SHEETS (Unaudited)

Southwestern Energy Company and Subsidiaries

December 31		**2011**		2010
		(in thousands)		
ASSETS				
Current Assets	**$**	**978,278**	$	580,893
Property and Equipment		**11,060,819**		8,980,885
Less: Accumulated depreciation, depletion and amortization		**4,415,339**		3,682,688
		6,645,480		5,298,197
Other Assets		**279,139**		138,373
	$	**7,902,897**	$	6,017,463
LIABILITIES AND EQUITY				
Current Liabilities	**$**	**884,913**	$	693,983
Long-Term Debt		**1,342,100**		1,093,000
Deferred Income Taxes		**1,586,798**		1,130,292
Long-Term Hedging Liability		**55**		40,188
Other Liabilities		**119,727**		95,124
Commitments and Contingencies				
Equity				
Common stock, $.01 par value; authorized 1,250,000,000 shares in 2011 and 2010, issued 349,058,501 shares in 2011 and 347,733,839 in 2010		**3,491**		3,477
Additional paid-in capital		**903,399**		862,423
Retained earnings		**2,656,214**		2,018,445
Accumulated other comprehensive income		**408,428**		83,975
Common stock in treasury, 98,889 shares in 2011 and 156,636 in 2010		**(2,228)**		(3,444)
Total equity		**3,969,304**		2,964,876
	$	**7,902,897**	$	6,017,463

STATEMENTS OF CASH FLOWS (Unaudited)

Southwestern Energy Company and Subsidiaries

Periods Ended December 31	Twelve Months 2011	2010
	(in thousands)	
Cash Flows From Operating Activities		
Net income (loss)	**$ 637,769**	$ 603,833
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	**707,966**	591,943
Deferred income taxes	**409,023**	379,720
Unrealized (gain) loss on derivatives	**(281)**	(4,289)
Stock-based compensation expense	**10,550**	9,820
Other	**991**	(1,348)
Change in assets and liabilities	**(26,201)**	62,906
Net cash provided by operating activities	**1,739,817**	1,642,585
Cash Flows From Investing Activities		
Capital investments	**(2,184,474)**	(2,073,174)
Proceeds from sale of property and equipment	**154,526**	350,227
Transfers to restricted cash	**(85,055)**	(356,035)
Transfers from restricted cash	**85,055**	356,035
Other items	**5,158**	(2,684)
Net cash used in investing activities	**(2,024,790)**	(1,725,631)
Cash Flows From Financing Activities		
Payments on short-term debt	**(1,200)**	(1,200)
Payments on revolving long-term debt	**(3,445,900)**	(2,958,100)
Borrowings under revolving long-term debt	**3,696,200**	3,054,800
Debt issuance costs and revolving credit facility costs	**(10,211)**	—
Excess tax benefit for stick-based compensation	**14,626**	—
Change in bank drafts outstanding	**24,637**	(11,545)
Proceeds from exercise of common stock options	**6,412**	3,897
Other	**(261)**	(1,612)
Net cash provided by (used in) financing activities	**284,303**	86,240
Effect of exchange rate changes on cash	**242**	(323)
Increase (decrease) in cash and cash equivalents	**(428)**	2,871
Cash and cash equivalents at beginning of year	**16,055**	13,184
Cash and cash equivalents at end of year	**$ 15,627**	$ 16,055

SEGMENT INFORMATION (Unaudited)

Southwestern Energy Company and Subsidiaries

	Exploration & Production	Midstream Services	Other	Eliminations	Total
			(in thousands)		
Quarter Ending December 31, 2011					
Revenues	**$ 538,830**	**$ 675,811**	**$ 867**	**$ (471,358)**	**$ 744,150**
Gas purchases	**—**	**555,356**	**—**	**(391,783)**	**163,573**
Operating expenses	**112,055**	**31,866**	**36**	**(78,776)**	**65,181**
General & administrative expenses	**38,173**	**7,642**	**70**	**(799)**	**45,086**
Depreciation, depletion & amortization	**179,995**	**10,091**	**245**	**—**	**190,331**
Taxes, other than income taxes	**12,767**	**3,302**	**20**	**—**	**16,089**
Operating Income	**$ 195,840**	**$ 67,554**	**$ 496**	**$ —**	**$ 263,890**
Capital Investments (1)	**$ 612,059**	**$ 22,778**	**$ 15,399**	**$ —**	**$ 650,236**
Quarter Ending December 31, 2010					
Revenues	$ 484,620	$ 616,430	$ 245	$ (430,864)	$ 670,431
Gas purchases	—	519,234	—	(365,628)	153,606
Operating expenses	93,129	23,195	—	(64,991)	51,333
General & administrative expenses	33,993	7,034	46	(245)	40,828
Depreciation, depletion & amortization	147,949	7,934	142	—	156,025
Taxes, other than income taxes	9,687	2,248	19	—	11,954
Operating Income	$ 199,862	$ 56,785	$ 38	$ —	$ 256,685
Capital Investments (1)	$ 502,565	$ 55,291	$ 28,429	$ —	$ 586,285
Twelve Months Ending December 31, 2011					
Revenues	**$ 2,100,488**	**$ 2,859,519**	**$ 3,268**	**$ (2,010,369)**	**$ 2,952,906**
Gas purchases	**—**	**2,418,092**	**—**	**(1,709,001)**	**709,091**
Operating expenses	**420,720**	**118,344**	**89**	**(298,209)**	**240,944**
General & administrative expenses	**134,840**	**26,091**	**269**	**(3,159)**	**158,041**
Depreciation, depletion & amortization	**666,125**	**37,261**	**1,125**	**—**	**704,511**
Taxes, other than income taxes	**53,665**	**11,779**	**74**	**—**	**65,518**
Operating Income	**$ 825,138**	**$ 247,952**	**$ 1,711**	**$ —**	**$ 1,074,801**
Capital Investments (1)	**$ 1,977,493**	**$ 160,776**	**$ 68,905**	**$ —**	**$ 2,207,174**
Twelve Months Ending December 31, 2010					
Revenues	$ 1,890,444	$ 2,453,840	$ 984	$ (1,734,605)	$ 2,610,663
Gas purchases	—	2,110,372	—	(1,499,211)	611,161
Operating expenses	335,705	90,476	—	(234,410)	191,771
General & administrative expenses	120,296	26,085	166	(984)	145,563
Depreciation, depletion & amortization	561,018	28,765	549	—	590,332
Taxes, other than income taxes	43,963	6,576	69	—	50,608
Operating Income (Loss)	$ 829,462	$ 191,566	$ 200	$ —	$ 1,021,228
Capital Investments (1)	$ 1,775,518	$ 271,316	$ 73,231	$ —	$ 2,120,065

(1) Capital investments include increases of $7.3 million and $19.2 million for the three-month periods ended December 31, 2011 and 2010, respectively, and increases of $4.3 million and $14.4 million for the twelve-month periods ended December 31, 2011 and 2010, respectively, relating to the change in accrued expenditures between periods.