

## **NEWS RELEASE**

### **SOUTHWESTERN ENERGY ANNOUNCES THIRD QUARTER 2011 FINANCIAL AND OPERATING RESULTS AND UPDATES PRODUCTION GUIDANCE**

Houston, Texas – October 27, 2011...Southwestern Energy Company (NYSE: SWN) today announced financial and operating results for the third quarter of 2011. Highlights include:

- Natural gas and crude oil production of 128.9 Bcfe, up from 105.0 Bcfe in the same period in 2010
- Record net cash provided by operating activities before changes in operating assets and liabilities of \$472.6 million (a non-GAAP measure reconciled below), up 12% from the same period in 2010
- Net income of \$175.2 million, up 9% from the same period in 2010

For the third quarter of 2011, Southwestern reported net income of \$175.2 million, or \$0.50 per diluted share, compared to \$160.7 million, or \$0.46 per diluted share, for the prior year period. Net cash provided by operating activities before changes in operating assets and liabilities (a non-GAAP measure; see reconciliation below) was \$472.6 million for the third quarter of 2011, up 12% from \$421.1 million in the third quarter of 2010.

“We had another excellent quarter,” stated Steve Mueller, President and Chief Executive Officer. “The increases in our earnings and cash flow were primarily driven by our production growth and our vertical integration and focus on costs continue to be key advantages for us. As a result of our Fayetteville and Marcellus projects, our production guidance has again been increased to approximately 496-500 Bcfe for the full year of 2011, which represents approximately a 23% increase over 2010 levels. With one of the lowest cost structures in our industry, a large inventory of wells to drill in the Fayetteville and Marcellus Shales and a growing New Ventures acreage position, we are well-positioned to provide profitable growth in production and reserves over the next several years.”

#### **Third Quarter 2011 Financial Results**

**E&P Segment** - Operating income from the company's E&P segment was \$228.5 million for the third quarter of 2011, up from \$216.7 million for the same period in 2010. The increase was primarily due to higher production volumes, which were partially offset by lower realized gas prices and increased operating costs and expenses.

Gas and oil production totaled 128.9 Bcfe in the third quarter of 2011, up 23% from

105.0 Bcfe in the third quarter of 2010, and included 111.9 Bcf from the company's Fayetteville Shale play, up from 92.3 Bcf in the third quarter of 2010. The company has updated its production guidance for the remainder of 2011 due to the strong performance from its Fayetteville Shale and Marcellus Shale operating areas. The revised total gas and oil production guidance for 2011 of 496 to 500 Bcfe is an increase of approximately 23% over the company's 2010 gas and oil production (using midpoints). Of the company's total expected production in 2011, approximately 430 to 434 Bcf is expected to come from the Fayetteville Shale. The company's production guidance for the remainder of 2011 as follows:

	1 <sup>st</sup> Quarter <u>Actual</u>	2 <sup>nd</sup> Quarter <u>Actual</u>	3 <sup>rd</sup> Quarter <u>Actual</u>	4 <sup>th</sup> Quarter <u>Estimate</u>	Full-Year 2011 <u>Estimate</u>
Previous Guidance (Bcfe)	115.0	119-121	123-125	126-130	483-491
Revised Guidance (Bcfe)	115.0	122.8	128.9	129-133	496-500

Including the effect of hedges, Southwestern's average realized gas price in the third quarter of 2011 was \$4.30 per Mcf, compared to \$4.67 per Mcf in the third quarter of 2010. The company's commodity hedging activities increased its average gas price by \$0.59 per Mcf during the third quarter of 2011, compared to an increase of \$0.76 per Mcf during the same period in 2010. At October 25, 2011, Southwestern had approximately 80 Bcf of its remaining 2011 projected natural gas production hedged through fixed price swaps and collars at a weighted average floor price of \$5.21 per Mcf. The company also 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 third quarter of 2011 was approximately \$0.49 per Mcf lower than average monthly NYMEX settlement prices, compared to approximately \$0.47 per Mcf lower during the third quarter of 2010. For the remainder of 2011, the company expects its total gas sales discount to NYMEX settlement prices to be \$0.45 to \$0.50 per Mcf. As of September 30, 2011, the company had protected approximately 55 Bcf of its fourth quarter 2011 expected gas production from the potential of widening basis differentials through hedging activities and sales arrangements at an average basis differential to NYMEX gas prices of approximately \$0.01 per Mcf, excluding transportation and fuel charges.

Lease operating expenses per unit of production for the company's E&P segment were \$0.86 per Mcfe in the third quarter of 2011, up from \$0.85 per Mcfe in the third quarter of 2010. The increase was primarily due to increased gathering and salt water disposal costs.

General and administrative expenses per unit of production were \$0.25 per Mcfe in the third quarter of 2011, compared to \$0.28 per Mcfe in the third 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 other employee-related costs primarily associated with the expansion of the company's

operations in the company's Fayetteville Shale properties and its Marcellus Shale properties.

Taxes other than income taxes per unit of production were \$0.11 per Mcfe in the third quarter of 2011, compared to \$0.12 per Mcfe in the third 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 was \$1.28 per Mcfe in the third quarter of 2011, down from \$1.31 per Mcfe in the third 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 \$66.8 million for the third quarter of 2011, up 25% from \$53.4 million for the third quarter of 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.

At October 27, 2011, the company's midstream segment was gathering approximately 2.0 Bcf per day through 1,745 miles of gathering lines in the Fayetteville Shale play area, up from approximately 1.7 Bcf per day through 1,524 miles of gathering lines a year ago. Gathering volumes, revenues and expenses for this segment are expected to continue to grow as reserves related to the company's Fayetteville Shale play are developed and production increases and as it develops its Marcellus Shale properties.

### **First Nine Months of 2011 Financial Results**

For the first nine months of 2011, Southwestern reported net income of \$479.2 million, or \$1.37 per diluted share, up from \$454.6 million, or \$1.30 per diluted share, for the first nine months of 2010. Net cash provided by operating activities before changes in operating assets and liabilities (a non-GAAP measure; see reconciliation below) was \$1.31 billion for the first nine months of 2011, up from \$1.18 billion for the same period in 2010.

**E&P Segment** - Operating income from the company's E&P segment was \$629.3 million for the nine months ended September 30, 2011, compared to \$629.6 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, offset by higher natural gas production volumes.

Gas and oil production was 366.7 Bcfe in the first nine months of 2011, up 25% compared to 293.3 Bcfe in the first nine months of 2010, and included 320.4 Bcf from the company's Fayetteville Shale play, up from 251.4 Bcfe in the first nine months of 2010.

Southwestern's average realized gas price for the first nine months of 2011 was \$4.24 per Mcf, including the effect of hedges, down 11% from \$4.76 per Mcf in the first nine months of 2010. The company's hedging activities increased the average gas price realized during the first nine months of 2011 by \$0.49 per Mcf, compared to an increase of \$0.64 per Mcf during the first nine months of 2010. Disregarding the impact of hedges, the average price received for the company's gas production during the first nine months of 2011 was approximately \$0.46 per Mcf lower than average monthly NYMEX settlement prices, compared to approximately \$0.47 per Mcf lower than NYMEX gas prices during the first nine months of 2010.

Lease operating expenses for the company's E&P segment were \$0.84 per Mcfe in the first nine months of 2011, up from \$0.83 per Mcfe in the first nine months of 2010. The increase was primarily due to increased gathering and salt water disposal costs.

General and administrative expenses were \$0.26 per Mcfe in the first nine months of 2011, down from \$0.29 per Mcfe in the first nine months of 2010. The decrease was primarily due to the effects of the company's increased production volumes which more than offset increased compensation and employee-related costs primarily associated with the expansion of the company's E&P operations in the company's Fayetteville Shale properties and its Marcellus Shale properties. Southwestern added 147 new employees during the first nine months of 2011, most of which were hired in its E&P segment.

Taxes other than income taxes were \$0.11 per Mcfe during the first nine months of 2011, compared to \$0.12 per Mcfe during the first nine months 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 \$1.29 per Mcfe in the first nine months of 2011, compared to \$1.35 per Mcfe in the first nine months of 2010, primarily due to the sale of certain East Texas oil and natural gas leases and wells in 2010 and 2011, as the proceeds from the sale were appropriately credited to the full cost pool, combined with lower finding and development costs.

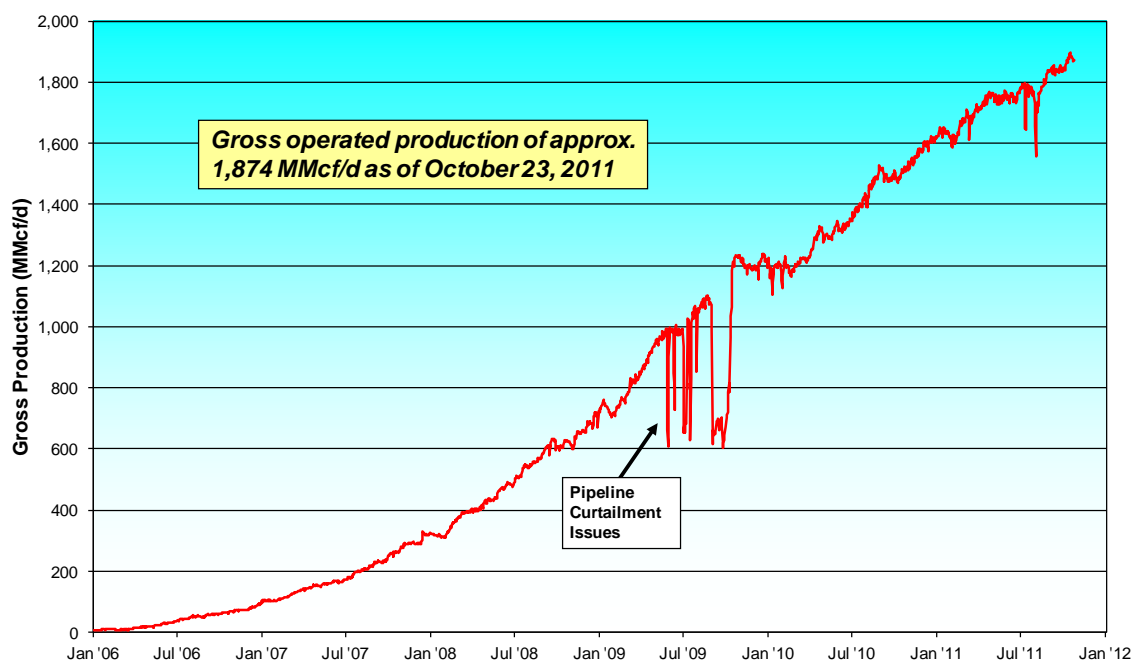
**Midstream Services** - Operating income for the company's midstream activities was \$180.4 million in the first nine months of 2011, compared to \$134.8 million in the first nine months of 2010. The increase in operating income was primarily due to increased gathering revenues related to the company's Fayetteville and Marcellus Shale properties, partially offset by increased operating costs and expenses.

**Capital Structure and Investments** - At September 30, 2011, the company had approximately \$1.3 billion in long-term debt and its long-term debt-to-total capitalization was 26%.

For the first nine months of 2011, Southwestern invested a total of approximately \$1.6 billion, compared to \$1.5 billion during the first nine months of 2010, which included \$1.4 billion invested in its E&P business and \$138 million invested in its Midstream Services segment. Of the approximately \$1.4 billion invested in its E&P business, \$1.0 billion was invested in its Fayetteville Shale play, \$170 million in Appalachia, \$138 million in New Ventures and \$67 million in East Texas and its conventional Arkoma Basin program.

### E&P Operations Review

**Fayetteville Shale Division** – During the third quarter of 2011, Southwestern placed a total of 132 operated wells on production in the Fayetteville Shale play, all of which were horizontal wells fracture stimulated using slickwater. At October 23, 2011, the company's gross production rate from the Fayetteville Shale play was approximately 1.9 Bcf per day, up from approximately 1.5 Bcf per day a year ago. The company is currently utilizing 19 drilling rigs in its Fayetteville Shale play, including 12 that are capable of drilling horizontal wells and 7 smaller rigs that are used to drill the vertical portion of the wells. The graph below provides gross production data from the company's operated wells in the Fayetteville Shale play area through October 23, 2011.



During the third 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 4,847 feet and average time to drill to total depth of 7.8 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 4,839 feet and average time to drill to total depth of 8.2 days from re-entry to re-entry in the second quarter of 2011. In the third quarter of 2011, the company had 25 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 80 wells drilled to total depth of 5 days or less from re-entry to re-entry.

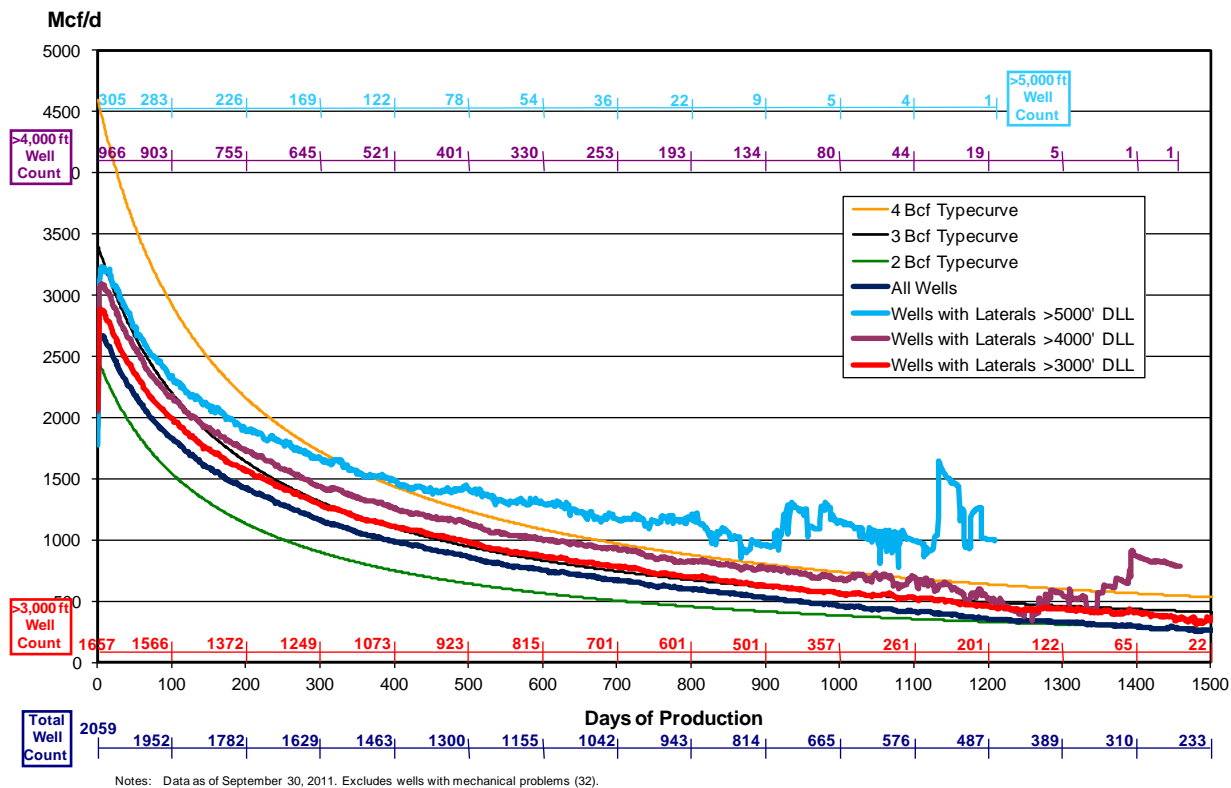
The company's wells placed on production during the third quarter of 2011 averaged initial production rates of 3,443 Mcf per day. Results from the company's drilling activities from 2007 by quarter are shown below.

<b>Time Frame</b>	<b>Wells Placed on Production</b>	<b>Average IP Rate (Mcf/d)</b>	<b>30th-Day Avg Rate (# of wells)</b>	<b>60th-Day Avg Rate (# of wells)</b>	<b>Average Lateral Length</b>
1 <sup>st</sup> Qtr 2007	58	1,261	1,066 (58)	958 (58)	2,104
2 <sup>nd</sup> Qtr 2007	46	1,497	1,254 (46)	1,034 (46)	2,512
3 <sup>rd</sup> Qtr 2007	74	1,769	1,510 (72)	1,334 (72)	2,622
4 <sup>th</sup> Qtr 2007	77	2,027	1,690 (77)	1,481 (77)	3,193
1 <sup>st</sup> Qtr 2008	75	2,343	2,147 (75)	1,943 (74)	3,301
2 <sup>nd</sup> Qtr 2008	83	2,541	2,155 (83)	1,886 (83)	3,562
3 <sup>rd</sup> Qtr 2008	97	2,882	2,560 (97)	2,349 (97)	3,736
4 <sup>th</sup> Qtr 2008 <sup>(1)</sup>	74	3,350 <sup>(1)</sup>	2,722 (74)	2,386 (74)	3,850
1 <sup>st</sup> Qtr 2009 <sup>(1)</sup>	120	2,992 <sup>(1)</sup>	2,537 (120)	2,293 (120)	3,874
2 <sup>nd</sup> Qtr 2009	111	3,611	2,833 (111)	2,556 (111)	4,123
3 <sup>rd</sup> Qtr 2009	93	3,604	2,624 (93)	2,255 (93)	4,100
4 <sup>th</sup> Qtr 2009	122	3,727	2,674 (122)	2,360 (120)	4,303
1 <sup>st</sup> Qtr 2010 <sup>(2)</sup>	106	3,197 <sup>(2)</sup>	2,388 (106)	2,123 (106)	4,348
2 <sup>nd</sup> Qtr 2010	143	3,449	2,554 (143)	2,321 (142)	4,532
3 <sup>rd</sup> Qtr 2010	145	3,281	2,448 (145)	2,202 (144)	4,503
4 <sup>th</sup> Qtr 2010	159	3,472	2,678 (159)	2,294 (159)	4,667
1 <sup>st</sup> Qtr 2011	137	3,231	2,604 (137)	2,238(137)	4,985
2 <sup>nd</sup> Qtr 2011	149	3,014	2,328 (149)	1,991 (149)	4,839
3 <sup>rd</sup> Qtr 2011	132	3,443	2,678 (108)	2,199 (60)	4,847

Note: Results as of September 30, 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 September 30, 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.

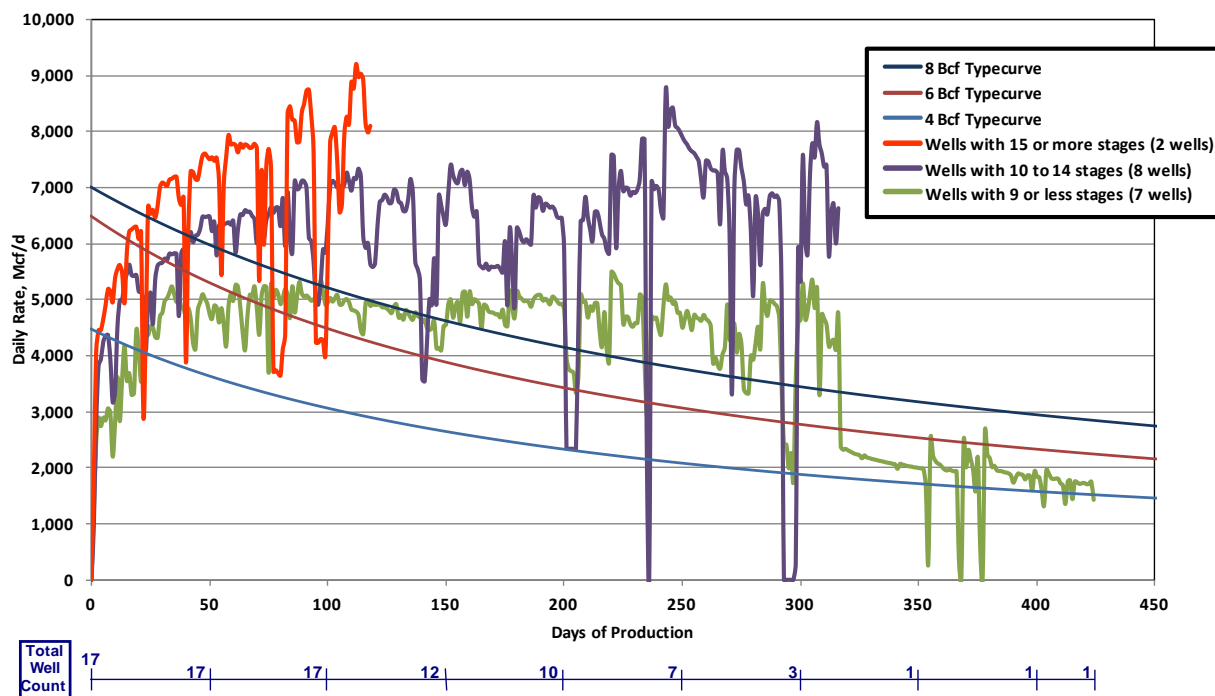


**Appalachia Division** – Southwestern has participated in a total of 40 wells in northeast Pennsylvania, of which 18 were producing and 22 were in progress at September 30, 2011. The producing wells are all operated Marcellus Shale wells located in its Greenzweig area in Bradford County. Net production from the area was 7.4 Bcf and 15.2 Bcf for three months and nine months ending September 30, 2011, respectively, compared to 0.2 Bcf and 0.2 Bcf for the same periods in 2010, respectively. The company is currently running 2 drilling rigs in Susquehanna County.

The company is currently completing a five-well pad in its Greenzweig area in Bradford County which is expected to be placed on production in November. The company also noted that the Ball Myer 1H well which was placed on production on June 23, 2011 is currently producing at a tubing constrained rate of approximately 8.2 MMcf per day at a flowing tubing pressure of 1,300 psi after 120 days of production. This well had a completed lateral of 4,502 feet and was fracture stimulated in 19 stages. In total, the company’s 17 horizontal wells have average completed lateral lengths of approximately 3,849 feet and have averaged 10.8 stages of completion. Gross operated production from the area is currently approximately 110 MMcf per day and constrained by a temporary pipeline curtailment.

The graph below provides normalized average daily production data through September 30, 2011, for the company’s horizontal wells in the Marcellus Shale. The “red curve” indicates results for two wells with 15 or more fracture stimulation stages, the “purple curve” indicates results for eight wells with 10 to 14 fracture stimulation stages and the “green curve” indicates results for seven wells with 9 or less 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 and 8 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 September 30, 2011.

**Ark-La-Tex Division** – Total net production from the company's East Texas and conventional Arkoma Basin properties was 9.6 Bcfe and 31.1 Bcfe for three months and nine months ending September 30, 2011, respectively. This compares to 12.5 Bcfe and 41.7 Bcfe for the same periods in 2010, respectively. The company participated in drilling 10 wells in these areas during the first nine months of 2011, 5 of which were operated.

In the second quarter of 2011, Southwestern sold certain oil and natural gas leases, wells and gathering equipment in Shelby, San Augustine and Sabine Counties in East Texas for approximately \$108.1 million, before customary purchase price adjustments. This divestiture included only the producing rights to the Haynesville and Middle Bossier Shale intervals in this acreage with net production of approximately 7.0 MMcf per day as of May 25, 2011 and proved net reserves of approximately 25.1 Bcf at December 31, 2010. At closing, the company deposited \$85 million of proceeds from this sale with a qualified intermediary to facilitate potential like-kind exchange transactions pursuant to Section 1031 of the Internal Revenue Code.

**New Ventures** – At September 30, 2011, Southwestern held 2,518,518 net undeveloped acres which were located in New Brunswick, Canada and approximately 948,000 net undeveloped acres in connection with other New Ventures prospects. In New Brunswick, the company has completed the second phase of surface geochemical

sampling and the acquisition phase of approximately 250 miles of 2-D data. Interpretation of both sets of data is underway.

Included in the approximately 948,000 net acres are 487,000 net acres located in the Lower Smackover Brown Dense formation, an unconventional oil reservoir found in southern Arkansas and northern Louisiana. The company spud its first well in September, the Roberson 18-19 #1-15H located in Columbia County, Arkansas, and is currently drilling the lateral portion of the well. This well has a vertical depth of approximately 9,200 feet and a planned horizontal lateral length of 4,000 feet. The well is expected to be completed in November. The company will spud its second well, the Garrett 7-23-5H #1 located in Claiborne Parish, Louisiana in November. This well has a planned total vertical depth of approximately 10,700 feet and a planned 7,900-foot horizontal lateral. The company plans to drill up to 8 additional wells as we continue to test the concept in 2012. If the company's drilling program yields positive results, it expects that activity in the play could increase significantly over the next several years.

#### 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 nine months ended September 30, 2011 and September 30, 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.

	<b>3 Months Ended Sept. 30,</b>	
	<b>2011</b>	<b>2010</b>
	(in thousands)	
<b>Cash flow from operating activities:</b>		
Net cash provided by operating activities	\$ 443,281	\$ 406,009
Add back (deduct):		
Change in operating assets and liabilities	29,313	15,051
Net cash provided by operating activities before changes in operating assets and liabilities	<u>\$ 472,594</u>	<u>\$ 421,060</u>

	<b>9 Months Ended Sept. 30,</b>	
	<b>2011</b>	<b>2010</b>
	(in thousands)	
<b>Cash flow from operating activities:</b>		
Net cash provided by operating activities	\$ 1,300,211	\$ 1,215,062
Add back (deduct):		
Change in operating assets and liabilities	12,129	(30,507)
Net cash provided by operating activities before changes in operating assets and liabilities	<u>\$ 1,312,340</u>	<u>\$ 1,184,555</u>

Southwestern will host a teleconference call on Friday, October 28, 2011, at 10:00 a.m. Eastern to discuss the company's third quarter 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 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. 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 plays; 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 formation; 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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The Right People doing the Right Things,  
wisely investing the cash flow from our  
underlying Assets, will create Value+®

Periods Ended September 30,	Three Months		Nine Months	
	2011	2010	2011	2010
<b><u>Exploration &amp; Production</u></b>				
<b>Production</b>				
Gas production (Bcf)	128.7	104.7	366.2	292.4
Oil production (MBbls)	24	44	79	137
Total equivalent production (Bcfe)	128.9	105.0	366.7	293.3
<b>Commodity Prices</b>				
Average gas price per Mcf, including hedges	\$ 4.30	\$ 4.67	\$ 4.24	\$ 4.76
Average gas price per Mcf, excluding hedges	\$ 3.71	\$ 3.91	\$ 3.75	\$ 4.12
Average oil price per Bbl	\$ 88.35	\$ 74.37	\$ 93.54	\$ 75.39
<b>Operating Expenses per Mcfe</b>				
Lease operating expenses	\$ 0.86	\$ 0.85	\$ 0.84	\$ 0.83
General & administrative expenses	\$ 0.25	\$ 0.28	\$ 0.26	\$ 0.29
Taxes, other than income taxes	\$ 0.11	\$ 0.12	\$ 0.11	\$ 0.12
Full cost pool amortization	\$ 1.28	\$ 1.31	\$ 1.29	\$ 1.35
<b><u>Midstream</u></b>				
Gas volumes marketed (Bcf)	153.3	130.2	450.4	357.0
Gas volumes gathered (Bcf)	190.9	155.7	545.7	421.6

**STATEMENTS OF OPERATIONS (Unaudited)**  
Southwestern Energy Company and Subsidiaries

Page 2 of 5

Periods Ended September 30,	Three Months		Nine Months	
	2011	2010	2011	2010
	<i>(in thousands, except share/per share amounts)</i>			
<b>Operating Revenues</b>				
Gas sales	\$ 551,757	\$ 483,886	\$ 1,543,667	\$ 1,378,873
Gas marketing	176,787	161,324	549,243	461,576
Oil sales	2,157	3,238	7,387	10,320
Gas gathering	36,541	33,715	107,961	87,303
Other	13	9	498	2,160
	<b>767,255</b>	<b>682,172</b>	<b>2,208,756</b>	<b>1,940,232</b>
<b>Operating Costs and Expenses</b>				
Gas purchases – midstream services	175,236	158,095	545,518	457,555
Operating expenses	63,911	52,929	175,763	140,438
General and administrative expenses	35,600	35,158	112,955	104,735
Depreciation, depletion and amortization	179,113	151,284	514,180	434,307
Taxes, other than income taxes	17,677	14,570	49,429	38,654
	<b>471,537</b>	<b>412,036</b>	<b>1,397,845</b>	<b>1,175,689</b>
<b>Operating Income</b>	<b>295,718</b>	<b>270,136</b>	<b>810,911</b>	<b>764,543</b>
<b>Interest Expense</b>				
Interest on debt	16,696	14,574	48,380	42,702
Other interest charges	902	503	3,414	1,447
Interest capitalized	(11,941)	(8,488)	(32,531)	(24,872)
	<b>5,657</b>	<b>6,589</b>	<b>19,263</b>	<b>19,277</b>
<b>Other Income (Loss), Net</b>	<b>(122)</b>	<b>326</b>	<b>321</b>	<b>265</b>
<b>Income Before Income Taxes</b>	<b>289,939</b>	<b>263,873</b>	<b>791,969</b>	<b>745,531</b>
<b>Provision for Income Taxes</b>				
Current	3,491	(5,274)	3,691	(2,574)
Deferred	111,275	108,509	309,042	293,690
	<b>114,766</b>	<b>103,235</b>	<b>312,733</b>	<b>291,116</b>
Net income	175,173	160,638	479,236	454,415
Less: Net loss attributable to noncontrolling interest	—	(103)	—	(192)
<b>Net Income Attributable to Southwestern Energy</b>	<b>\$ 175,173</b>	<b>\$ 160,741</b>	<b>\$ 479,236</b>	<b>\$ 454,607</b>
<b>Earnings Per Share</b>				
Net income attributable to Southwestern Energy stockholders				
– Basic	\$ 0.50	\$ 0.47	\$ 1.38	\$ 1.32
Net income attributable to Southwestern Energy stockholders				
– Diluted	\$ 0.50	\$ 0.46	\$ 1.37	\$ 1.30
<b>Weighted Average Common Shares Outstanding</b>				
Basic	347,239,793	345,587,569	347,070,330	345,326,985
Diluted	349,998,789	349,228,576	349,891,885	349,308,957

September 30,	2011	2010
	<i>(in thousands)</i>	
<b>ASSETS</b>		
Current Assets	\$ 836,120	\$ 961,196
Property and Equipment	10,444,393	8,382,654
Less: Accumulated depreciation, depletion and amortization	4,230,121	3,515,411
	6,214,272	4,867,243
Other Assets	163,715	164,285
	\$ 7,214,107	\$ 5,992,724
<b>LIABILITIES AND EQUITY</b>		
Current Liabilities	\$ 766,250	\$ 646,142
Long-Term Debt	1,271,000	1,289,400
Deferred Income Taxes	1,461,205	1,061,579
Long-Term Hedging Liability	4,582	25,751
Other Long-Term Liabilities	102,517	89,351
Commitments and Contingencies		
Equity		
Common stock, \$0.01 par value; authorized 1,250,000,000 shares in 2011 and 2010; issued 348,264,799 shares in 2011 and 346,978,646 in 2010	3,483	3,470
Additional paid-in capital	880,425	848,206
Retained earnings	2,497,681	1,868,934
Accumulated other comprehensive income	229,750	155,006
Common stock in treasury, 125,984 shares in 2011 and 207,994 in 2010	(2,786)	(4,510)
Total Southwestern Energy Stockholders' Equity	3,608,553	2,871,106
Noncontrolling Interest	—	9,395
Total Equity	3,608,553	2,880,501
	\$ 7,214,107	\$ 5,992,724

**STATEMENTS OF CASH FLOWS (Unaudited)**  
Southwestern Energy Company and Subsidiaries

Page 4 of 5

Periods Ended September 30,	Nine Months	
	2011	2010
	<i>(in thousands)</i>	
<b>Cash Flows From Operating Activities</b>		
Net income	\$ 479,236	\$ 454,415
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	516,891	435,515
Deferred income taxes	309,042	293,690
Unrealized gain (loss) on derivatives	905	(3,504)
Stock-based compensation	6,619	6,612
Other	(353)	(2,173)
Change in assets and liabilities	(12,129)	30,507
Net cash provided by operating activities	<b>1,300,211</b>	1,215,062
<b>Cash Flows From Investing Activities</b>		
Capital investments	(1,543,549)	(1,506,079)
Proceeds from sale of property and equipment	121,546	348,379
Transfers to restricted cash	(85,040)	(355,865)
Transfers from restricted cash	15,779	1,689
Other	4,940	(2,632)
Net cash used in investing activities	<b>(1,486,324)</b>	(1,514,508)
<b>Cash Flows From Financing Activities</b>		
Payments on current portion of long-term debt	(600)	(600)
Payments on revolving long-term debt	(2,575,000)	(2,043,600)
Borrowings under revolving long-term debt	2,753,600	2,336,100
Change in bank drafts outstanding	10,621	5,546
Proceeds from exercise of common stock options	4,844	3,013
Revolving credit facility costs	(10,211)	—
Net cash provided by financing activities	<b>183,254</b>	300,459
Effect of exchange rate changes on cash	97	—
Increase (decrease) in cash and cash equivalents	(2,762)	1,013
Cash and cash equivalents at beginning of year	16,055	13,184
Cash and cash equivalents at end of period	<b>\$ 13,293</b>	<b>\$ 14,197</b>

	Exploration & Production	Midstream Services	Other	Eliminations	Total
<i>(in thousands)</i>					
<b>Quarter Ending September 30, 2011</b>					
Revenues	\$ 555,620	\$ 743,831	\$ 832	\$ (533,028)	\$ 767,255
Gas purchases	—	629,899	—	(454,663)	175,236
Operating expenses	111,444	30,001	34	(77,568)	63,911
General & administrative expenses	32,615	3,718	64	(797)	35,600
Depreciation, depletion & amortization	169,391	9,414	308	—	179,113
Taxes, other than income taxes	13,694	3,962	21	—	17,677
Operating Income	<u>\$ 228,476</u>	<u>\$ 66,837</u>	<u>\$ 405</u>	<u>\$ —</u>	<u>\$ 295,718</u>
Capital Investments <sup>(1)</sup>	\$ 421,182	\$ 32,158	\$ 17,095	\$ —	\$ 470,435
<b>Quarter Ending September 30, 2010</b>					
Revenues	\$ 491,900	\$ 646,909	\$ 247	\$ (456,884)	\$ 682,172
Gas purchases	—	552,539	—	(394,444)	158,095
Operating expenses	89,176	25,947	—	(62,194)	52,929
General & administrative expenses	29,600	5,768	36	(246)	35,158
Depreciation, depletion & amortization	143,457	7,684	143	—	151,284
Taxes, other than income taxes	12,971	1,581	18	—	14,570
Operating Income	<u>\$ 216,696</u>	<u>\$ 53,390</u>	<u>\$ 50</u>	<u>\$ —</u>	<u>\$ 270,136</u>
Capital Investments <sup>(1)</sup>	\$ 420,294	\$ 77,006	\$ 19,330	\$ —	\$ 516,630
<b>Nine Months Ending September 30, 2011</b>					
Revenues	\$ 1,561,658	\$ 2,183,708	\$ 2,401	\$ (1,539,011)	\$ 2,208,756
Gas purchases	—	1,862,736	—	(1,317,218)	545,518
Operating expenses	308,665	86,478	53	(219,433)	175,763
General & administrative expenses	96,667	18,449	199	(2,360)	112,955
Depreciation, depletion & amortization	486,130	27,170	880	—	514,180
Taxes, other than income taxes	40,898	8,477	54	—	49,429
Operating Income	<u>\$ 629,298</u>	<u>\$ 180,398</u>	<u>\$ 1,215</u>	<u>\$ —</u>	<u>\$ 810,911</u>
Capital Investments <sup>(1)</sup>	\$ 1,365,434	\$ 137,998	\$ 53,506	\$ —	\$ 1,556,938
<b>Nine Months Ending September 30, 2010</b>					
Revenues	\$ 1,405,824	\$ 1,837,410	\$ 739	\$ (1,303,741)	\$ 1,940,232
Gas purchases	—	1,591,138	—	(1,133,583)	457,555
Operating expenses	242,576	67,281	—	(169,419)	140,438
General & administrative expenses	86,303	19,051	120	(739)	104,735
Depreciation, depletion & amortization	413,069	20,831	407	—	434,307
Taxes, other than income taxes	34,276	4,328	50	—	38,654
Operating Income	<u>\$ 629,600</u>	<u>\$ 134,781</u>	<u>\$ 162</u>	<u>\$ —</u>	<u>\$ 764,543</u>
Capital Investments <sup>(1)</sup>	\$ 1,272,953	\$ 216,025	\$ 44,802	\$ —	\$ 1,533,780

(1) Capital investments include reductions of \$60.9 million and \$29.8 million for the three-month periods ended September 30, 2011 and 2010, respectively, and reductions of \$3.0 million and \$4.8 million for the nine-month periods ended September 30, 2011 and 2010, respectively, relating to the change in accrued expenditures between periods.