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NEWS RELEASE

SOUTHWESTERN ENERGY ANNOUNCES RECORD 2010 FINANCIAL AND OPERATING RESULTS

Company Reports Production and Reserve Growth of 35%, Reserve Replacement of 430% and Finding Cost of $1.02 per Mcfe in 2010

Houston, Texas – February 24, 2011...Southwestern Energy Company (NYSE: SWN) today announced its financial and operating results for the fourth quarter and the year ended December 31, 2010. Calendar year 2010 highlights include:

- Gas and oil production of 404.7 Bcfe, up 35% over 2009
- Proved oil and gas reserves of 4,937 Bcfe, up 35% over 2009
- Net income of $604.1 million, up 16% from adjusted net income in 2009
- Net cash provided by operating activities before changes in operating assets and liabilities (a non-GAAP measure reconciled below) of approximately $1.6 billion, up 10% from 2009

“2010 marked another record year for Southwestern Energy,” remarked Steve Mueller, President and Chief Executive Officer of Southwestern Energy. “Despite lower realized gas prices, we set new records in 2010 for production, reserves, earnings and cash flow. We posted production growth of 35% and our total proved reserves grew significantly as well, reaching over 4.9 Tcfe. Our low cost structure is the key in the current gas price environment, as our finding and development cost of $1.02 per Mcfe and production costs of $0.93 per Mcfe for 2010 are among the lowest in our industry.”

“As we look forward, we are both realistic and optimistic. We are profitable and will continue to look for ways to become more efficient, drive our margins higher and be disciplined with our capital investments. We are also optimistic about what lies ahead. We kicked off our Marcellus drilling program in 2010 and look forward to testing at least one exploration idea later this year. Overall, I am very proud of our results in 2010 and believe that 2011 will be an exciting year for Southwestern Energy.”

Fourth Quarter of 2010 Financial Results

For the fourth quarter of 2010, Southwestern reported net income of $149.5 million, or $0.43 per diluted share, compared to $157.8 million, or $0.45 per diluted share, for the same period in 2009. The decrease was primarily due to lower realized natural gas prices which more than offset a 25% increase in production. Net cash provided by operating activities before changes in operating assets and liabilities (a non-GAAP measure; see reconciliation below), was $395.1 million in the fourth quarter of 2010, compared to $411.4 million in the same period in 2009.

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E&P Segment - Operating income from the company's E&P segment was $199.9 million for the fourth quarter of 2010, compared to $223.7 million for the same period in 2009. The decrease was primarily due to an 18% decrease in realized natural gas prices which more than offset the increase in production volumes.

Gas and oil production totaled 111.4 Bcfe in the fourth quarter of 2010, up 25% from 89.0 Bcfe in the fourth quarter of 2009, and included 98.8 Bcf from the company's Fayetteville Shale play, up from 73.9 Bcf in the fourth quarter of 2009.

Including the effect of hedges, Southwestern's average realized gas price in the fourth quarter of 2010 was $4.33 per Mcf, down from $5.29 per Mcf in the fourth quarter of 2009. The company's commodity hedging activities increased its average gas price by $0.93 per Mcf during the fourth quarter of 2010, compared to an increase of $1.51 per Mcf during the same period in 2009. As of February 24, 2011, Southwestern had NYMEX fixed price hedges in place on notional volumes of 186.2 Bcf of its 2011 gas production at a weighted average floor price of $5.30 per Mcf.

Disregarding the impact of commodity price hedges, the company's average price received for its gas production during the fourth quarter of 2010 was approximately $0.40 per Mcf lower than average NYMEX settlement prices, compared to approximately $0.39 per Mcf lower during the fourth quarter of 2009. As of February 24, 2011, the company had protected approximately 64 Bcf of its first 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 $0.05 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. In 2011, the company expects its total gas sales discount to NYMEX to be $0.45 to $0.50 per Mcf.

Lease operating expenses per unit of production for the company's E&P segment were $0.84 per Mcfe in the fourth quarter of 2010, up from $0.79 per Mcfe in the fourth quarter of 2009. The increase was primarily due to increased gathering, compression and water disposal costs related to its Fayetteville Shale operations.

General and administrative expenses per unit of production were $0.31 per Mcfe in the fourth quarter of 2010, down from $0.37 per Mcfe in the fourth quarter of 2009. 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 Fayetteville Shale play.

Taxes other than income taxes per unit of production were $0.09 per Mcfe in the fourth quarter of 2010, down from $0.14 per Mcfe in the fourth quarter of 2009. Taxes other than income taxes vary due to changes in severance and ad valorem taxes that result from the mix of the company's volumes and fluctuations in commodity prices.

The company's full cost pool amortization rate decreased to $1.32 per Mcfe in the fourth quarter of 2010, compared to $1.40 per Mcfe in the fourth quarter of 2009. The decrease in the average amortization rate was primarily due to lower finding and development costs as well as the sale of certain East Texas oil and gas leases and wells in the second quarter of 2010 as the proceeds from the sale were 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, impairments 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. The future full cost pool amortization rate cannot be predicted with accuracy due to the variability of each of the factors discussed above, as well as other factors.

Midstream Services - Operating income for the company's Midstream Services segment, which is comprised of natural gas gathering and marketing activities, was $56.8 million for the three months ended December 31, 2010, up from $42.4 million in the same period in 2009. The increase in operating income was primarily due to the increase in gathering revenues related to the company's Fayetteville Shale play, partially offset by increased operating costs and expenses.

Full-Year 2010 Financial Results

Southwestern reported net income of $604.1 million in 2010, or $1.73 per diluted share, compared to a net loss for 2009 of $35.7 million, or $0.10 per diluted share, which resulted from a $907.8 million non-cash ceiling test impairment ($558.3 million net of taxes) of the company's natural gas and oil properties resulting from lower natural gas and oil prices which was taken in the first quarter of 2009. Excluding the non-cash impairment, Southwestern's adjusted net income for 2009 was $522.7 million (a non-GAAP measure; see reconciliation below), or $1.52 per diluted share.

Net cash provided by operating activities before changes in operating assets and liabilities (a non-GAAP measure; see reconciliation below), was approximately $1.6 billion in 2010, up 10% from approximately $1.4 billion in 2009.

***E&P Segment* -** Operating income from the company's E&P segment was $829.5 million in 2010, compared to an operating loss of $157.7 million in 2009, resulting from the recognition of a $907.8 million non-cash ceiling test impairment of its natural gas and oil properties recorded for the first three months ended March 31, 2009. Excluding the non-cash ceiling test impairment, operating income from the company's E&P segment was $750.1 million in 2009 (a non-GAAP measure; see reconciliation below). The increase in the segment's operating income in 2010 was primarily due to higher production volumes which were partially offset by lower realized natural gas prices and increased operating costs and expenses.

Gas and oil production was 404.7 Bcfe in 2010, up 35% compared to 300.4 Bcfe in 2009, and included 350.2 Bcf from the company's Fayetteville Shale play, up from 243.5 Bcf in 2009. Southwestern's 2011 total gas and oil production guidance is 465 to 475 Bcfe, an increase of approximately 15% to 17% over its 2010 production.

Southwestern's average realized gas price was $4.64 per Mcf, including the effect of hedges, in 2010 compared to $5.30 per Mcf in 2009. The company's hedging activities increased the average gas price realized in 2010 by $0.71 per Mcf, compared to an increase of $1.96 per Mcf in 2009. Disregarding the impact of hedges, the average price received for the company's gas production during 2010 was approximately $0.46 per Mcf lower than average NYMEX settlement prices, compared to approximately $0.65 per Mcf lower than NYMEX settlement prices in 2009.

Lease operating expenses for the company's E&P segment were $0.83 per Mcfe in 2010, up from $0.77 per Mcfe in 2009. The increase was primarily due to increased gathering and compression costs and increased costs associated with higher water disposal volumes in the company's Fayetteville Shale operations.

General and administrative expenses were $0.30 per Mcfe in 2010, down from $0.35 per Mcfe in 2009. 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 Fayetteville Shale play.

Taxes other than income taxes were $0.11 per Mcfe in both 2010 and 2009.

The company's full cost pool amortization rate decreased to $1.34 per Mcfe in 2010, compared to $1.51 per Mcfe in 2009, primarily due to the $907.8 million non-cash ceiling test impairment recorded in the first quarter of 2009, lower finding and development costs and the sale of natural gas and oil properties in the second quarter of 2010, as the sales proceeds were credited to the full cost pool.

Midstream Services - Operating income for the company's midstream activities was $191.6 million in 2010, compared to $122.6 million in 2009. The increase in operating income was primarily due to increased gathering revenues and an increase in the margin from gas marketing activities related to the Fayetteville Shale play, partially offset by increased operating costs and expenses. At December 31, 2010, the company's midstream segment was gathering approximately 1.8 Bcf per day through 1,569 miles of gathering lines in the Fayetteville Shale play, compared to gathering approximately 1.3 Bcf per day through 1,137 miles of gathering lines at December 31, 2009. 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 Appalachian properties. The company is currently considering various strategic alternatives for maximizing and/or recognizing the value of this asset.

Capital Structure and Investments - At December 31, 2010, the company had approximately $1.1 billion in long-term debt and its long-term debt-to-total capitalization ratio had declined to 27.0%, down from 29.9% at December 31, 2009. On February 14, 2011, Southwestern amended and restated its revolving credit facility which was scheduled to expire in February 2012. Among other things, the maturity date of this unsecured credit facility was extended to February 2016 and the borrowing capacity was increased to $1.5 billion from $1.0 billion with an accordion feature that permits the company to increase the facility to $2.0 billion with agreement of existing or new lenders.

In 2010, Southwestern invested approximately $2.1 billion, up from approximately $1.8 billion in capital investments in 2009, and included approximately $1.8 billion invested in its E&P business and $271 million invested in its Midstream Services segment. Of the approximate $1.8 billion invested in its E&P business, $1.3 billion was invested in its Fayetteville Shale play, $150 million in East Texas, $118 million in Appalachia, $13 million in its conventional Arkoma Basin program and $145 million in New Ventures.

The company expects that its total capital investments for the full year of 2011 to be approximately $1.9 billion, which includes approximately $1.15 billion invested in its Fayetteville Shale play, $265 million in Appalachia, $170 million in New Ventures, a combined $30 million in its East Texas and conventional Arkoma Basin programs, $225 million in Midstream Services and $60 million for corporate and other purposes.

Southwestern Reports Record Gas and Oil Reserves

Southwestern's estimated proved gas and oil reserves totaled 4,937 Bcfe at December 31, 2010, up 35% from 3,657 Bcfe at the end of 2009. Approximately 100% of the company's year-end 2010 estimated proved reserves were natural gas and 55% were classified as proved developed, compared to 100% and 54%, respectively, in 2009.

The following table details additional information relating to reserve estimates as of and for the year ended December 31, 2010:

	Natural Gas (Bcf)	Crude Oil (MMBbls)	Total (Bcfe)
Proved Reserves, Beginning of Year	3,650.3	1.1	**3,656.7**
Revisions of Previous Estimates	309.3	0.1	**309.6**
Extensions, Discoveries, & Other Additions	1,429.4	0.3	**1,431.1**
Production	(403.6)	(0.2)	**(404.7)**
Acquisition of Reserves in Place	----	----	----
Disposition of Reserves in Place	(55.4)	----	**(55.4)**
Proved Reserves, End of Year	4,930.0	1.2	**4,937.3**
Proved, Developed Reserves:			
Beginning of Year	1,972.8	1.0	**1,978.9**
End of Year	2,687.2	1.2	**2,694.3**

Note: Figures may not add due to rounding

In 2010, Southwestern replaced 430% of its production volumes with an increase of 1,431.1 Bcfe of proved natural gas and oil reserves as a result of its drilling program and net upward revisions of 309.6 Bcfe. Of the reserve additions, 698.0 Bcfe were proved developed and 733.2 Bcfe were proved undeveloped. The upward reserve revisions during 2010 were primarily due to 266.7 Bcf in upward revisions related to the improved performance of wells in the company's Fayetteville Shale play and positive reserve revisions of 78.4 Bcfe due to a comparative increase in the average gas price for 2010 as compared to 2009. The company also had net upward revisions of 2.7 Bcfe and 34.2 Bcf in its East Texas and conventional Arkoma Basin operating areas, respectively. Additionally, the company's reserves decreased by 55.4 Bcfe as a result of the sale of certain oil and gas leases and wells in East Texas. In 2009, the company's reserve replacement ratio was 592%, including revisions. For the period ending December 31, 2010, the company's three-year average reserve replacement ratio, including revisions, was 505%. Excluding reserve revisions, the company's 2010 and three-year average reserve replacement ratios were 354% and 449%, respectively.

Southwestern's finding and development cost was $1.02 per Mcfe in 2010, including reserve revisions, compared to $0.86 per Mcfe in 2009. For the period ending December 31, 2010, the company's three-year finding and development cost, including revisions, was $1.07 per Mcfe. Excluding reserve revisions, the company's 2010 and three-year average finding and development costs were $1.24 per Mcfe and $1.21 per Mcfe, respectively (finding and development costs are considered by the SEC to be non-GAAP financial measures and have been 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 2010 based on average fiscal year prices, and its well count, net acreage and PV-10 as of December 31, 2010 and sets forth 2010 annual information related to production and capital investments for each of its operating areas:

2010 Proved Reserves by Category and Summary Operating Data

		U.S. Exploitation				
	Fayetteville Shale Play	East Texas	Arkoma Basin	Appalachia	New Ventures	Total
Estimated Proved Reserves:						
Natural Gas (Bcf):						
Developed (Bcf)	2,213	266	197	11	-	**2,687**
Undeveloped (Bcf)	2,132	55	29	27	-	**2,243**
	4,345	321	226	38	-	**4,930**
Crude Oil (MMBbls):						
Developed (MMBbls)	-	1	-	-	-	**1**
Undeveloped (MMBbls)	-	-	-	-	-	**-**
	-	1	-	-	-	**1**
Total Proved Reserves (Bcfe)(1):						
Proved Developed (Bcfe)	2,213	273	197	11	-	**2,694**
Proved Undeveloped (Bcfe)	2,132	55	29	27	-	**2,243**
	4,345	328	226	38	-	**4,937**
Percent of Total	88%	7%	4%	1%	-	**100%**
Percent Proved Developed	51%	83%	87%	29%	-	**55%**
Percent Proved Undeveloped	49%	17%	13%	71%	-	**45%**
Production (Bcfe)	350.2	34.3	19.2	1.0	-	**404.7**
Capital Investments (millions)(2)	$ 1,333	$ 150	$ 13	$ 118	$ 145	**$ 1,759**
Total Gross Producing Wells	2,120	605	1,185	8	-	**3,918**
Total Net Producing Wells	1,437	465	572	7	-	**2,481**
Total Net Acreage	790,898(3)	125,563(4)	433,109(5)	173,009(6)	3,009,643(7)	**4,532,222**
Net Undeveloped Acreage	367,206(3)	53,228(4)	250,657(5)	169,095(6)	3,009,643(7)	**3,849,829**
PV-10:						
Pre-tax (millions)(8)	$ 3,604	$ 352	$ 261	$ 45	$ -	**$ 4,262**
PV of taxes (millions)(8)	1,056	103	76	13	-	**1,248**
After-tax (millions)(8)	$ 2,548	$ 249	$ 185	$ 32	$ -	**$ 3,014**
Percent of Total	85%	8%	6%	1%	-	**100%**
Percent Operated(9)	95%	98%	87%	100%	-	**95%**

(1) The company has no reserves from synthetic gas, synthetic oil or nonrenewable natural resources intended to be upgraded into synthetic gas or oil. The company's proved reserves increased by 1,431.1 Bcfe as a result of its drilling program and net upward revisions of 309.6 Bcfe in 2010. Of the reserve additions, 698.0 Bcfe were proved developed and 733.2 Bcfe were proved undeveloped. The company uses standard engineering and geoscience methods, or a combination of methodologies in determining estimates of material properties, including performance and test data analysis, offset statistical analogy of performance data, volumetric evaluation, including analysis of petrophysical parameters. Such parameters include 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, etc.).

(2) The company's Total and Fayetteville Shale play capital investments exclude $13 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 17,502 net acres in 2011, 3,711 net acres in 2012 and 215,194 net acres in 2013.

(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 22,827 net acres in 2011, 6,371 net acres in 2012 and 1,388 net acres in 2013.

(5) Includes 123,442 net developed acres and 1,544 net undeveloped acres in the Arkoma Basin that are also within our 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 32,720 net acres in 2011, 29,699 net acres in 2012 and 2,971 net acres in 2013.

(6) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 2,325 net acres in 2011, 63,117 net acres in 2012 and 43,077 net acres in 2013.

(7) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 19,735 net acres in 2011, 22,500 net acres in 2012 and 60 net acres in 2013. 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.

(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 its proved oil and gas reserves.

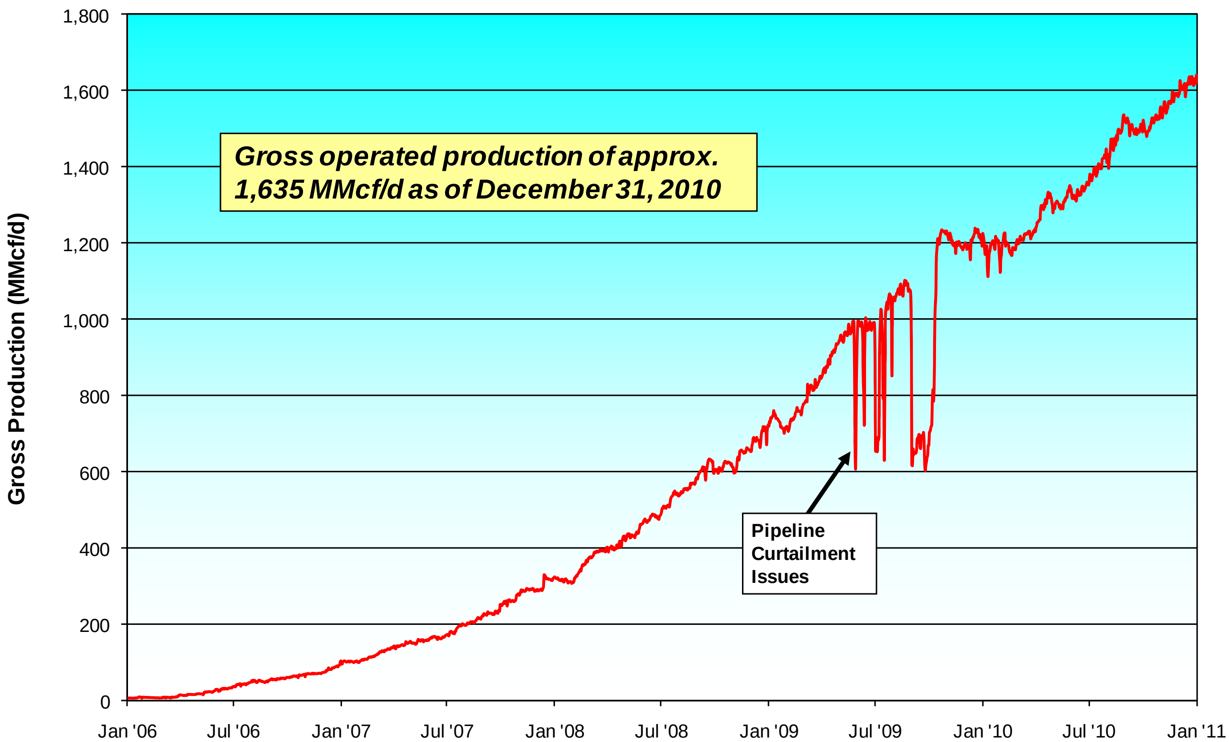
(9) Based upon pre-tax PV-10 of proved developed producing properties.

2010 E&P Operations Review

Southwestern invested a total of approximately $1.8 billion in its E&P business during 2010 and participated in drilling 713 wells, 483 of which were successful, 3 were dry (including 2 wells in the Fayetteville Shale play that were plugged and abandoned due to mechanical issues encountered during drilling) and 227 were in progress at year-end. Of the 227 wells in progress at year-end, 201 were located in the company's Fayetteville Shale play. Of the $1.8 billion invested, approximately $1.4 billion was in exploratory and development drilling and workovers, $200 million for acquisition of properties, $17 million for seismic expenditures and $172 million in capitalized interest and expenses and other technology-related expenditures. Additionally, the company invested approximately $13 million related to its drilling rig related equipment, sand facility and other equipment.

Fayetteville Shale Play - As of December 31, 2010, Southwestern had spud a total of 2,445 wells in the play since its commencement in 2004, 2,001 of which were operated and 444 of which were outside-operated wells. Of the wells spud, 658 were in 2010 compared to 570 wells in 2009. At year-end 2010, 1,820 operated wells had been drilled and completed overall, including 1,730 horizontal wells.

Southwestern's net production from the Fayetteville Shale play was 350.2 Bcf in 2010, up 44% from 243.5 Bcf in 2009, as gross production from the company's operated wells in the Fayetteville Shale play increased from approximately 1,225 MMcf per day at the beginning of 2010 to approximately 1,635 MMcf per day by year-end. The graph below provides gross production data from the company's operated wells in the Fayetteville Shale play area through December 31, 2010.



Southwestern added approximately 1.6 Tcf in new reserves in its Fayetteville Shale drilling program during 2010 at a finding and development cost of $0.86 per Mcf (finding and development costs are considered by the SEC to be non-GAAP financial measures and have been computed below), including positive reserve revisions of approximately 266.7 Bcf due primarily to improved well performance and 6.4 Bcf of positive revisions due to a comparative increase in gas prices. During 2009, the company added approximately 1.8 Tcf in new reserves in the Fayetteville Shale play at a finding and development cost of $0.69 per Mcf, including positive reserve revisions of approximately 384.8 Bcf due primarily to improved well performance and 147.1 Bcf of negative revisions due to a comparative decrease in gas prices.

The company's total proved net reserves booked in the Fayetteville Shale play at year-end 2010 were 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. Of the 3,682 locations, 3,610 were horizontal. The average gross proved reserves for the undeveloped wells included in its year-end reserves was approximately 2.4 Bcf per well, up from 2.2 Bcf per well at year-end 2009. Total proved net gas reserves booked in the play at year-end 2009 totaled approximately 3,117 Bcf from a total of 2,675 locations, of which 1,428 were proved developed producing, 97 were proved developed non-producing and 1,150 were proved undeveloped.

During 2010, the company continued to improve its drilling practices in the Fayetteville Shale play. The company's operated horizontal wells had an average completed 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. This compares to an average completed operated well cost of $2.9 million per well, average horizontal lateral length of 4,100 feet and average time to drill to total depth of 12 days from re-entry to re-entry during 2009. The company placed 553 operated wells on production during 2010 that averaged initial production rates of 3,364 Mcf per day, compared to average initial production rates of 3,478 Mcf per day in 2009. Results for 2010 included 220 operated wells (or 40% of total operated wells) placed on production that were the first well in a new section, compared to 2009 results which had 142 wells placed on production that were the first well in a new section (or 32% of total operated wells). During 2010, Southwestern placed 72 operated wells on production with initial production rates that exceeded 5.0 MMcf per day, including 17 wells that exceeded 6.0 MMcf per day and the play's highest rate well, the Harlan 09-10 #1-12H located in Cleburne County, which was placed on production with an initial production rate of approximately 8.7 MMcf per day with a 3,900-foot completed lateral.

During the fourth quarter of 2010, the company's operated horizontal wells had an average completed well cost of $2.7 million per well, average horizontal lateral length of 4,667 feet and average time to drill to total depth of 8.2 days from re-entry to re-entry. This compares to an average completed operated well cost of $2.8 million per well, average horizontal lateral length of 4,503 feet and average time to drill to total depth of 11 days from re-entry to re-entry in the third quarter of 2010. In the fourth quarter of 2010, the company had 13 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. The company currently has 20 drilling rigs running in its Fayetteville Shale play area, 12 that are capable of drilling horizontal wells and 8 smaller rigs that are used to drill the vertical portion of the wells.

The company placed 159 operated wells on production during the fourth quarter of 2010 which averaged initial production rates of 3,472 Mcf per day, up 6% from average initial production rates of 3,281 Mcf per day in the third quarter of 2010. Results for the fourth quarter of 2010 include 39 operated wells (or 25%) placed on production which were the first well in a new section, compared to 56 wells (or 39%) in the third quarter of 2010. The company also placed 2 wells on production with initial production rates over 7.0 MMcf per day during the fourth quarter. 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	2,640 (92)	2,275 (92)	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	2,575 (141)	2,329 (141)	4,532
3rd Qtr 2010	145	3,281	2,448 (145)	2,202 (144)	4,503
4th Qtr 2010	159	3,472	2,632 (123)	2,239 (71)	4,667

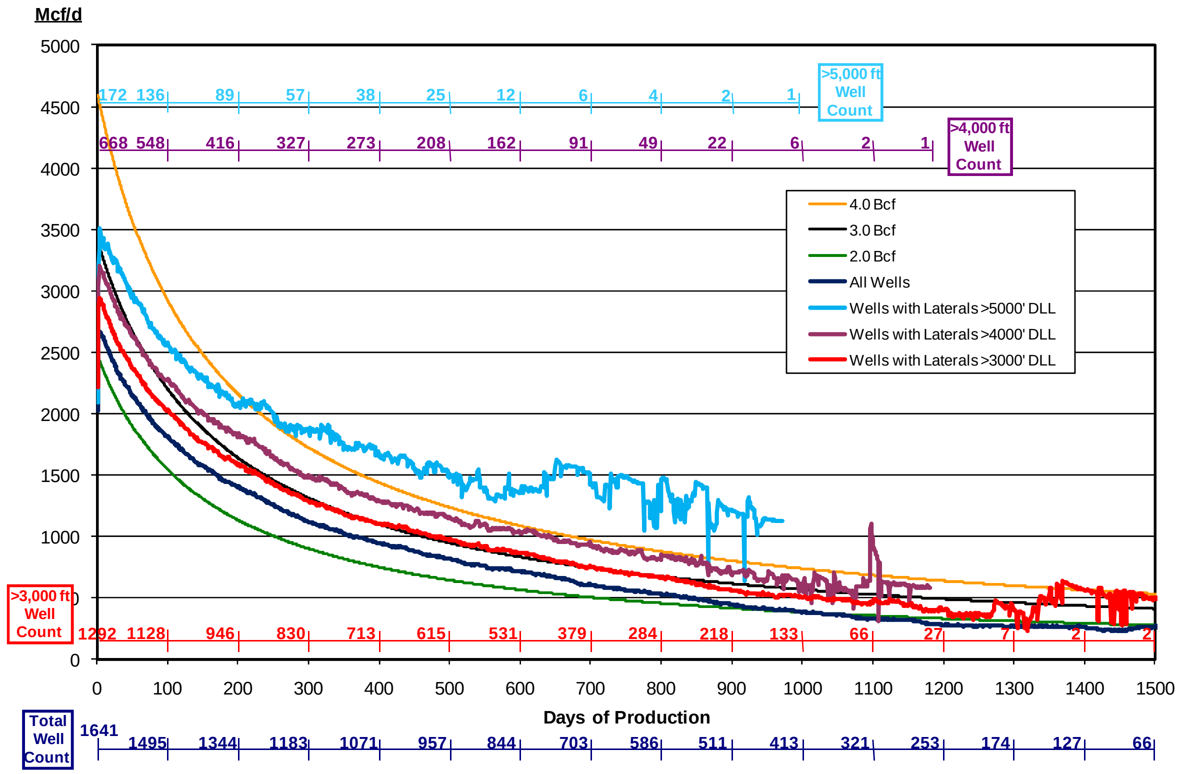
Note: Results as of December 31, 2010.

(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 company continues to test tighter well spacing and, at December 31, 2010, had placed 645 wells on production that have well spacing of 700 feet or less, representing approximately 65-acre spacing or less. Previously, the company has stated that based on the wells drilled to date, it believes that approximately 20% of the approximately 600,000 net acres drilled to date can be developed at 30- to 40-acre spacing, approximately 40% can be developed at 65-acre spacing and the remaining 40% of that acreage needs more results from testing to determine if development on tighter spacing than 65-acres would be economic. At December 31, 2010, the company had drilled nearly all of its well spacing tests and over 80% of these wells are currently on production. The company expects to have additional production data by the end of the first quarter of 2011 on the remaining 40% of that acreage where more results were needed. In addition, the company is in the process of performing interference testing on certain of its closer-spaced areas.

The graph below provides normalized average daily production data through December 31, 2010, 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 2.0, 3.0 and 4.0 Bcf typecurves are shown solely for reference purposes and are not intended to be projections of the performance of the company's wells.



At December 31, 2010, Southwestern held leases for approximately 915,884 net acres in the Fayetteville Shale play area (367,206 net undeveloped acres, 423,692 net developed acres held by Fayetteville Shale production, 123,442 net developed acres held by conventional production and an additional 1,544 net undeveloped acres in the traditional Fairway).

In 2011, Southwestern plans to invest approximately $1.15 billion in the Fayetteville Shale play, which includes participating in approximately 530 to 540 gross horizontal wells, 440 to 450 of which will be operated by the company.

Appalachia - Southwestern began leasing in northeastern Pennsylvania in 2007 and at December 31, 2010, the company had approximately 173,009 net acres in Pennsylvania.

In 2010, Southwestern invested approximately $118 million in Pennsylvania and participated in 21 wells, of which 6 were successful and 15 were in progress at year-end, resulting in a 100% success rate and adding new reserves of 38 Bcf. These 6 wells are all operated horizontal Marcellus Shale wells located in its Greenzweig area in Bradford County that production tested between 4 and 8 MMcf per day, resulting in net production from its Pennsylvania properties of 1.0 Bcf in 2010.

In February 2011, the company placed 3 additional operated horizontal wells on production, all of which were located in the Greenzweig area. Daily gross operated production from the area is currently approximately 45 MMcf per day without compression, with flowing tubing pressures ranging from 1,100 to 1,300 psi and choke sizes ranging from 23/64” to 40/64”.

In 2011, Southwestern expects its Marcellus activity to grow substantially from 2010 levels with two operated rigs currently being utilized. The company plans to invest approximately $265 million in Appalachia, which includes participating in a total of 40 to 45 wells, all of which will be operated.

New Ventures - As of December 31, 2010, Southwestern held 3,009,643 net undeveloped acres in connection with its New Ventures prospects, of which 2,518,518 net acres were located in New Brunswick, Canada.

In March 2010, the company announced that the Department of Natural Resources of the Province of New Brunswick, Canada accepted its bids for exclusive licenses to search and conduct an exploration program covering 2,518,518 net acres in the province in order to test new hydrocarbon basins. As a result, Southwestern is required to make investments of approximately CAD $47 million in the province over the next three years. The three-year exploration program represents the company's first venture outside of the United States. In January 2011, the company received initial information from a geochemical survey it had conducted during 2010. Nearly 2,000 samples were taken in more than 35 traverses. All of the traverses had signatures indicating some combination of oil and gas source rocks.

In 2010, Southwestern invested approximately $145 million in its New Ventures program, of which approximately $10.7 million was invested in New Brunswick, Canada. In 2011, the company plans to invest approximately $170 million in various unconventional, exploration and New Ventures projects, which includes drilling in at least one new area.

Other Areas - At December 31, 2010, Southwestern had approximately 328 Bcfe of reserves in East Texas, compared to 330 Bcfe at year-end 2009. In 2010, the company invested approximately $150 million in East Texas and participated in 25 wells, of which 17 were successful and 8 were in progress at year-end, resulting in a 100% success rate and adding new reserves of 85 Bcfe. This area recorded net upward revisions of 2.7 Bcfe, comprised of upward revisions of approximately 41.6 Bcfe primarily due to a comparative increase in the average 2010 gas price from the average 2009 gas price, offset by 38.9 Bcfe of negative performance revisions. Net production from East Texas was 34.3 Bcfe in 2010, compared to 34.9 Bcfe in 2009. In 2010, the company sold certain oil and natural gas leases, wells and gathering equipment in East Texas for approximately $357.8 million to Exco Resources, Inc. The sale included only the producing rights to the Haynesville and Middle Bossier Shale intervals in approximately 20,063 net acres. The net production from the Haynesville and Middle Bossier Shale intervals in this acreage was approximately 13.5 MMcf per day and proved net reserves were approximately 55.4 Bcf when the sale was closed in June 2010.

At December 31, 2010, Southwestern had approximately 226 Bcf of reserves that were attributable to its conventional Arkoma properties, compared to 208 Bcf at year-end 2009. In 2010, the company invested approximately $13 million in its conventional Arkoma drilling program and participated in 9 wells, of which 5 were successful and 3 were in progress at year-end, resulting in an 83% success rate and adding new reserves of 3 Bcf. This area recorded net upward revisions of approximately 34 Bcf, comprised of upward price revisions of approximately 30 Bcf primarily due to a comparative increase in the average 2010 price from the average 2009 price, in addition to an increase of 4 Bcf of positive performance revisions. Net production from the company's conventional Arkoma properties was 19.2 Bcf in 2010, compared to 22.0 Bcf in 2009.

In 2011, Southwestern plans to reduce the combined amount of investments in these areas to approximately $30 million.

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 December 31, 2010 and December 31, 2009. 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.

	12 Months Ended Dec. 31,	
	2010	**2009**
	(in thousands)	
Net income (loss) attributable to Southwestern Energy:		
Net income (loss) attributable to Southwestern Energy	$ 604,118	$ (35,650)
Add back:		
Impairment of natural gas and oil properties (net of taxes)	--	558,305

Net income attributable to Southwestern Energy, excluding impairment of natural gas and oil properties	$ 604,118	$ 522,655

	12 Months Ended Dec. 31,	
	2010	2009
Diluted earnings per share:		
Net income (loss) per share attributable to Southwestern Energy stockholders	$ 1.73	$ (0.10)
Add back:		
Impairment of natural gas and oil properties (net of taxes)	--	1.62
Net income per share attributable to Southwestern Energy stockholders, excluding impairment of natural gas and oil properties	$ 1.73	$ 1.52

	3 Months Ended Dec. 31,	
	2010	2009
	(in thousands)	
Cash flow from operating activities:		
Net cash provided by operating activities	$ 427,523	$ 369,850
Add back (deduct):		
Change in operating assets and liabilities	(32,399)	41,554
Net cash provided by operating activities before changes in operating assets and liabilities	$ 395,124	$ 411,404

	12 Months Ended Dec. 31,	
	2010	2009
	(in thousands)	
Cash flow from operating activities:		
Net cash provided by operating activities	$ 1,642,585	$ 1,359,376
Add back (deduct):		
Change in operating assets and liabilities	(62,906)	81,652
Net cash provided by operating activities before changes in operating assets and liabilities	$ 1,579,679	$ 1,441,028

	12 Months Ended Dec. 31,	
	2010	2009
	(in thousands)	
E&P segment operating income:		
E&P segment operating income (loss)	$ 829,462	$ (157,725)
Add back:		
Impairment of natural gas and oil properties	--	907,812
E&P segment operating income, excluding impairment of natural gas and oil properties	$ 829,462	$ 750,087

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, 2010 and December 31, 2009, and three years ending December 31, 2010.

	For the 12 Months Ending December 31, 2010	For the 12 Months Ending December 31, 2009	For the 3 Years Ending December 31, 2010	Fayetteville Shale Play 2010	Fayetteville Shale Play 2009
Total exploration, development and acquisition costs incurred ($ in thousands)	$ 1,781,424	$ 1,529,876	$ 4,871,295	$ 1,351,535	$ 1,259,151
Reserve extensions, discoveries and acquisitions (MMcfe)	1,431,125	1,685,191	4,036,497	1,305,609	1,576,980
Finding & development costs, excluding revisions ($/Mcfe)	$ 1.24	$ 0.91	$ 1.21	$ 1.04	$ 0.80
Reserve extensions, discoveries, acquisitions and reserve revisions (MMcfe)	1,740,717	1,778,045	4,537,043	1,578,722	1,814,665
Finding & development costs, including revisions ($/Mcfe)	$ 1.02	$ 0.86	$ 1.07	$ 0.86	$ 0.69

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 Friday, February 25, 2011, at 10:00 a.m. Eastern to discuss the company's fourth quarter and year-end 2010 results. The toll-free number to call is 877-407-8035 and the international toll-free 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 fund the company's planned capital investments; 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 impact of government regulation, including any increase in severance or similar taxes, legislation relating to hydraulic fracturing, the climate and over the counter derivatives; the costs and availability of oilfield personnel, services and drilling supplies, raw materials, and equipment, including pressure pumping equipment and crews; the company's ability to determine the most effective and economic fracture stimulation for the Fayetteville Shale formation; the company's future property acquisition or divestiture activities; the impact of the adverse outcome of any material litigation against the company; the effects of weather; increased competition and regulation; 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	**2010**	2009	**2010**	2009
Exploration & Production				
Production				
Natural gas production (Bcf)	**111.2**	88.9	**403.6**	299.7
Oil production (MBbls)	**34**	29	**171**	124
Total equivalent production (Bcfe)	**111.4**	89.0	**404.7**	300.4
Commodity Prices				
Average gas price per Mcf, including hedges	**$ 4.33**	$ 5.29	**$ 4.64**	$ 5.30
Average gas price per Mcf, excluding hedges	**$ 3.40**	$ 3.78	**$ 3.93**	$ 3.34
Average oil price per Bbl	**$ 82.70**	$ 72.52	**$ 76.84**	$ 54.99
Operating Expenses per Mcfe				
Lease operating expenses	**$ 0.84**	$ 0.79	**$ 0.83**	$ 0.77
General & administrative expenses	**$ 0.31**	$ 0.37	**$ 0.30**	$ 0.35
Taxes, other than income taxes	**$ 0.09**	$ 0.14	**$ 0.11**	$ 0.11
Full cost pool amortization	**$ 1.32**	$ 1.40	**$ 1.34**	$ 1.51

	Three Months		Twelve Months	
Midstream				
Gas volumes marketed (Bcf)	**138.8**	108.6	**495.8**	382.5
Gas volumes gathered (Bcf)	**166.7**	119.7	**588.3**	387.1

STATEMENTS OF OPERATIONS (Unaudited)

Southwestern Energy Company and Subsidiaries

	Three Months		Twelve Months	
Periods Ended December 31	**2010**	2009	**2010**	2009
	(in thousands, except share/per share amounts)			
Operating Revenues				
Gas sales	**$ 477,368**	$ 468,205	**$ 1,856,241**	$ 1,578,256
Gas marketing	**154,337**	132,011	**615,913**	488,663
Oil sales	**2,791**	2,163	**13,111**	6,843
Gas gathering	**35,609**	23,410	**122,912**	74,281
Other	**326**	(1,296)	**2,486**	(2,264)
	670,431	624,493	**2,610,663**	2,145,779
Operating Costs and Expenses				
Gas purchases – midstream services	**153,606**	129,513	**611,161**	482,836
Operating expenses	**51,333**	39,965	**191,771**	136,541
General and administrative expenses	**40,828**	37,767	**145,563**	122,618
Depreciation, depletion and amortization	**156,025**	137,670	**590,332**	493,658
Impairment of natural gas and oil properties	**—**	—	**—**	907,812
Taxes, other than income taxes	**11,954**	13,317	**50,608**	37,280
	413,746	358,232	**1,589,435**	2,180,745
Operating Income (Loss)	**256,685**	266,261	**1,021,228**	(34,966)
Interest Expense				
Interest on debt	**14,442**	13,910	**57,144**	55,581
Other interest charges	**488**	997	**1,935**	3,266
Interest capitalized	**(8,044)**	(8,296)	**(32,916)**	(40,209)
	6,886	6,611	**26,163**	18,638
Other Income, Net	**162**	361	**427**	1,449
Income (Loss) Before Income Taxes	**249,961**	260,011	**995,492**	(52,155)
Provision (Benefit) for Income Taxes				
Current	**14,513**	(8,765)	**11,939**	(64,969)
Deferred	**86,030**	110,984	**379,720**	48,606
	100,543	102,219	**391,659**	(16,363)
Net income (loss)	**149,418**	157,792	**603,833**	(35,792)
Less: Net loss attributable to noncontrolling interest	**(93)**	(34)	**(285)**	(142)
Net Income (Loss) Attributable to Southwestern Energy	**$ 149,511**	$ 157,826	**$ 604,118**	$ (35,650)
Earnings Per Share				
Net income (loss) attributable to Southwestern Energy stockholders - Basic	**$ 0.43**	$ 0.46	**$ 1.75**	$ (0.10)
Net income (loss) attributable to Southwestern Energy stockholders - Diluted	**$ 0.43**	$ 0.45	**$ 1.73**	$ (0.10)
Weighted Average Common Shares Outstanding				
Basic	**346,337,014**	344,410,199	**345,581,568**	343,420,568
Diluted	**349,351,156**	349,268,735	**349,310,666**	343,420,568

BALANCE SHEETS (Unaudited)
Southwestern Energy Company and Subsidiaries

December 31	**2010**	2009
	(in thousands)	
ASSETS		
Current Assets	**$ 580,893**	$ 564,501
Property and Equipment	**8,980,885**	7,181,784
Less: Accumulated depreciation, depletion and amortization	**3,682,688**	3,054,531
	5,298,197	4,127,253
Other Assets	**138,373**	78,496
	$ 6,017,463	$ 4,770,250
LIABILITIES AND EQUITY		
Current Liabilities	**$ 693,983**	$ 536,416
Long-Term Debt	**1,093,000**	997,500
Deferred Income Taxes	**1,130,292**	811,902
Long-Term Hedging Liability	**40,188**	3,057
Other Liabilities	**95,124**	80,394
Commitments and Contingencies		
Equity		
Common stock, $.01 par value; authorized 1,250,000,000 shares in 2010 and 540,000,000 shares in 2009, issued 347,733,839 shares in 2010 and 346,081,210 in 2009	**3,477**	3,461
Additional paid-in capital	**862,423**	833,494
Retained earnings	**2,018,445**	1,414,327
Accumulated other comprehensive income	**83,975**	84,276
Common stock in treasury, 156,636 shares in 2010 and 203,830 in 2009	**(3,444)**	(4,333)
Total Southwestern Energy stockholders' equity	**2,964,876**	2,331,225
Noncontrolling interest	**—**	9,756
Total equity	**2,964,876**	2,340,981
	$ 6,017,463	$ 4,770,250

STATEMENTS OF CASH FLOWS (Unaudited)

Southwestern Energy Company and Subsidiaries

Periods Ended December 31	Twelve Months 2010	2009
	(in thousands)	
Cash Flows From Operating Activities		
Net income (loss)	**$ 603,833**	$ (35,792)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	**591,943**	495,291
Impairment of natural gas and oil properties	**—**	907,812
Deferred income taxes	**379,720**	48,606
Unrealized (gain) loss on derivatives	**(4,289)**	5,309
Stock-based compensation expense	**9,820**	10,177
Other	**(1,348)**	9,625
Change in assets and liabilities	**62,906**	(81,652)
Net cash provided by operating activities	**1,642,585**	1,359,376
Cash Flows From Investing Activities		
Capital investments	**(2,073,174)**	(1,780,165)
Proceeds from sale of property and equipment	**350,227**	818
Transfers to restricted cash	**(356,035)**	—
Transfers from restricted cash	**356,035**	—
Other items	**(2,684)**	(1,257)
Net cash used in investing activities	**(1,725,631)**	(1,780,604)
Cash Flows From Financing Activities		
Payments on short-term debt	**(1,200)**	(61,200)
Payments on revolving long-term debt	**(2,958,100)**	(1,371,700)
Borrowings under revolving long-term debt	**3,054,800**	1,696,200
Change in bank drafts outstanding	**(11,545)**	(30,920)
Proceeds from exercise of common stock options	**3,897**	5,755
Other	**(1,612)**	—
Net cash provided by (used in) financing activities	**86,240**	238,135
Effect of exchange rate changes on cash	**(323)**	—
Increase (decrease) in cash and cash equivalents	**2,871**	(183,093)
Cash and cash equivalents at beginning of year	**13,184**	196,277
Cash and cash equivalents at end of year	**$ 16,055**	$ 13,184

SEGMENT INFORMATION (Unaudited)

Southwestern Energy Company and Subsidiaries

	Exploration & Production	Midstream Services	Other	Eliminations	Total
			(in thousands)		
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**
Quarter Ending December 31, 2009					
Revenues	$ 471,431	$ 512,483	$ 112	$ (359,533)	$ 624,493
Gas purchases	—	439,468	—	(309,955)	129,513
Operating expenses	70,510	18,920	—	(49,465)	39,965
General & administrative expenses	32,683	5,178	19	(113)	37,767
Depreciation, depletion & amortization	132,094	5,707	(131)	—	137,670
Taxes, other than income taxes	12,447	844	26	—	13,317
Operating Income	$ 223,697	$ 42,366	$ 198	$ —	$ 266,261
Capital Investments (1)	$ 379,041	$ 46,766	$ 15,109	$ —	$ 440,916
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	**$ 829,462**	**$ 191,566**	**$ 200**	**$ —**	**$ 1,021,228**
Capital Investments (1)	**$ 1,775,518**	**$ 271,316**	**$ 73,231**	**$ —**	**$ 2,120,065**
Twelve Months Ending December 31, 2009					
Revenues	$ 1,593,231	$ 1,603,332	$ 687	$ (1,051,471)	$ 2,145,779
Gas purchases	—	1,375,824	—	(892,988)	482,836
Operating expenses	230,447	64,129	—	(158,035)	136,541
General & administrative expenses	105,017	17,989	60	(448)	122,618
Depreciation, depletion & amortization	474,014	19,213	431	—	493,658
Impairment of natural gas and oil properties	907,812	—	—	—	907,812
Taxes, other than income taxes	33,666	3,557	57	—	37,280
Operating Income (Loss)	$ (157,725)	$ 122,620	$ 139	$ —	$ (34,966)
Capital Investments (1)	$ 1,565,450	$ 214,208	$ 29,459	$ —	$ 1,809,117

(1) Capital investments include increases of $19.2 million and $24.6 million for the three-month periods ended December 31, 2010 and 2009, respectively, and increases of $14.4 million and $12.2 million for the twelve-month periods ended December 31, 2010 and 2009, respectively, relating to the change in accrued expenditures between periods.