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SOUTHWESTERN ENERGY CO

FORM 8-K
(Current report filing)

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SIC Code	1311 - Crude Petroleum and Natural Gas
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Date of report (Date of earliest event reported): October 31 , 2011

SOUTHWESTERN ENERGY COMPANY
(Exact name of registrant as specified in its charter)

Delaware
(State or other jurisdiction of incorporation)

1 -08246
(Commission File Number)

71-0205415
(IRS Employer Identification No.)

2350 N. Sam Houston Pkwy. E., Suite 125,
Houston, Texas
(Address of principal executive offices)

77032
(Zip Code)

(281) 618-4700
(Registrant's telephone number, including area code)

Not Applicable
(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

- ☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
- ☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
- ☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))
- ☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Explanatory Note

The information in this report, including Exhibit 99.1 attached hereto, shall not be deemed to be "filed" for purposes of Section 18 of the Securities and Exchange Act of 1934, as amended (the "Exchange Act"), or otherwise subject to the liabilities of that Section, and shall not be incorporated by reference into any filing under the Securities Act of 1933, as amended, or the Exchange Act, except as shall be expressly set forth by specific reference in such a filing.

Section 7 - Regulation FD

Item 7.01 Regulation FD Disclosure.

On October 31, 2011, Southwestern Energy Company (the "Company") will make a presentation available to investors. The presentation includes updated guidance for the 2011 fiscal year regarding the Company's projected net income, diluted earnings per share, net cash provided by operating activities before changes in operating assets and liabilities ("Net Cash Flow") and earnings before interest, taxes, depreciation, depletion and amortization ("EBITDA"). Net Cash Flow and EBITDA are non-GAAP measures that are reconciled on slides 34 and 36 of the presentation, respectively. A copy of the presentation is furnished herewith as Exhibit 99.1 .

All statements in the presentation, 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. 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 disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

Exhibits. The following exhibits are being furnished as part of this Report.

Exhibit Number	Description
99.1	Transcript of slideshow accompanying the November 2011 presentation.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

SOUTHWESTERN ENERGY COMPANY

Dated: October 31, 2011

By: /s/ GREG D. KERLEY

Name: Greg D. Kerley
Title: Executive Vice President and Chief Financial Officer

EXHIBIT INDEX

Exhibit Number	Description
99.1	Transcript of slideshow accompanying the November 2011 presentation.

EXHIBIT 99.1

Slide Presentation dated November 2011

(Cover)
Southwestern Energy

November 2011 Update

NYSE: SWN

The left side of this slide contains a photograph of a thin section of rock taken at 100 times magnification. The caption of the photograph reads "Core Value +." The company's formula is located in the bottom right corner of the picture. The top-right corner of this slide contains the company logo.

(Slide 1)
Southwestern Energy Company

General Information

Southwestern Energy Company is an integrated natural gas company whose wholly-owned subsidiaries are engaged in natural gas and oil exploration and production and natural gas gathering and marketing.

Market Data as of October 27, 2011

NYSE: SWN	
Shares of Common Stock Outstanding	348,339,433
Market Capitalization	$15,159,732,124
Institutional Ownership	88.2%
Management and Board Ownership	2.8%
52-Week Price Range	$32.30 (10/3/11) - $49.00 (7/22/11)

Investor Contacts

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(Slide 2)
Forward-Looking Statements

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.

The SEC has generally permitted oil and gas companies, in their filings with the SEC, to disclose only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. We use the terms "estimated ultimate recovery," "EUR," "probable," "possible," and "non-proven" reserves, reserve "potential" or "upside" or other descriptions of volumes of reserves potentially recoverable through additional drilling or recovery techniques that the SEC's guidelines may prohibit us from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of being actually realized by the company.

The contents of this presentation are current as of October 28, 2011.

(Slide 3)
About Southwestern

*** Focused on exploration and production of natural gas.**
** 4.9 Tcfe of reserves; 12.2 R/P at year-end 2010.*

*** E&P strategy built on organic growth through the drillbit.**
** Over 70% of planned E&P capital allocated to drilling in 2011.*

*** Track record of adding significant reserves at low costs.**
** From 2005 to 2010, we've averaged over 40% annual production and reserve growth and annually replaced almost 500% of our production at a F&D cost of $1.32 per Mcfe.*

*** Proven management team has increased Southwestern's market capitalization from $187 million at year-end 1998 to approximately $15 billion today.**

*** Strategy built on the Formula:**

The *Right People* doing the *Right Things* , wisely investing the cash flow from the underlying *Assets* will create *Value+* .

Note that the information contained on this slide constitutes a "Forward-Looking Statement".

(Slide 4)
Recent Developments

* First Nine Months of 2011 Highlights

* Discretionary cash flow (1) of $1.3 billion, up 11%.

* Production of 366.7 Bcfe, up 25%, due to strong Fayetteville and Marcellus results.

* Drilling on 487,000 net acre position in a new unconventional horizontal oil play targeting the Lower Smackover Brown Dense formation in southern Arkansas and northern Louisiana.

* Strong Growth and Low-Cost Operations Set the Stage for a Record 2011

* 2011 planned capital investment program of $2.0 billion.

* 2011 gas and oil production projected to grow approximately 23% to 496-500 Bcfe.

* One of the lowest cost operators in the industry – finding and development costs (2) of $1.02 per Mcfe and cash

operating costs (3) of $1.30 per Mcfe in 2010.

* Strong balance sheet and financial position as of September 30, 2011:
    * Debt-to-total capitalization ratio of 26%.
    * Increased capacity of revolving credit facility to $1.5 billion in February 2011.

(1) Discretionary cash flow is net cash flow before changes in operating assets and liabilities and is a non-GAAP financial measure (see explanation and reconciliation on page 35).

(2) Includes reserve revisions and excludes capital investments in our sand facility, drilling rig related and ancillary equipment of approximately $13 million. Excluding revisions and capital investments in our sand facility, drilling rig related and ancillary equipment, our finding and development cost was $1.24/Mcfe.

(3) Cash operating costs for the year ended December 31, 2010, include lease operating expenses ($0.83/Mcfe), general and administrative expenses ($0.30/Mcfe), taxes other than income taxes ($0.11/Mcfe) and net interest expense ($0.06/Mcfe).

Note that the information contained on this slide constitutes a "Forward-Looking Statement".

(Slide 5)
Proven Track Record

This slide contains bar charts for the periods ended December 31.

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Production (Bcfe)	36	40	40	41	54	61	72	113	195	300	405	496-500E
Reserve Replacement (%)	211%	155%	215%	313%	364%	399%	386%	474%	523%	592%	430%	
EBITDA ($MM) (1)	$ 104	$ 134	$ 99	$ 151	$ 255	$ 346	$ 415	$ 675	$ 1,362	$ 1,368	$ 1,612	
F&D Cost ($/Mcfe)	$ 0.92	$ 1.59	$ 0.99	$ 1.32	$ 1.43	$ 1.70	$ 2.72	$ 2.55	$ 1.53	$ 0.86	$ 1.02	

Note: Reserve data includes reserve revisions and excludes capital investments in our sand facility, drilling rig related and ancillary equipment.

(1) EBITDA is a non-GAAP financial measure. See explanation and reconciliation of EBITDA on page 36.

Note that the information contained on this slide constitutes a "Forward-Looking Statement".

(Slide 6)
Areas of Operations

This slide contains a map of Arkansas, Louisiana, Oklahoma, Texas and Pennsylvania with shadings to denote the Conventional Arkoma Basin, the East Texas region, the Fayetteville Shale and the Marcellus Shale.

Exploration & Production Segment

* 2010: 4,937 Bcfe of Reserves
    ~100% Natural Gas
    Production – 404.7 Bcfe
* 2011 Est. Production: 496-500 Bcfe

Conventional Arkoma

* Reserves: 226 Bcf (4%)
* Production: 19.2 Bcf (5%)
* Net Acres: 308,123 (12/31/10)

Fayetteville Shale

* Reserves: 4,345 Bcf (88%)
* Production: 350.2 Bcf (87%)
* Net Acres: 915,884 (12/31/10)

East Texas

* Reserves: 328 Bcfe (7%)
* Production: 34.3 Bcfe (8%)
* Net Acres: 125,563 (12/31/10)

Marcellus Shale

* Reserves: 38 Bcf (< 1%)
* Production: 1.0 Bcf (< 1%)
* Net Acres: 173,009 (12/31/10)

* Southwestern's E&P segment operates in Arkansas, Texas, Oklahoma and Pennsylvania.
* Midstream Services segment provides marketing and gathering services for the E&P business.

Notes: Conventional Arkoma acreage excludes 124,986 net acres in the conventional Arkoma Basin operating area that are also within the company's Fayetteville Shale focus area.

Note that the information contained on this slide constitutes a "Forward-Looking Statement".

(Slide 7)
Capital Investments

This slide contains a bar chart of company capital investments, summarized as follows:

	2005	2006	2007	2008	2009	2010	2011 Plan
				(in millions)			
Corporate & Other	$16	$32	$16	$17	$29	$73	$60
Midstream Services	16	49	107	183	214	271	225
Drilling Rigs	35	94	5	-	-	-	-
Property Acquisitions	-	18	2	-	4	1	-
Cap. Expense & Other E&P	32	62	77	153	190	185	255
Leasehold & Seismic	61	70	166	149	114	216	195
Development Drilling	287	421	1,110	1,255	1,254	1,369	1,251
Exploration Drilling	36	196	20	39	4	5	14
Total	**$483**	**$942**	**$1,503**	**$1,796**	**$1,809**	**$2,120**	**$2,000**

This slide also contains a pie chart of the company's planned 2011 capital investments by area of operation, summarized as follows:

	% of Total Capital Investments
Arkoma Fayetteville Shale	61%
Appalachia	15%
Midstream	10%
New Ventures	9%
Corp/Other	3%
Other Areas	2%

* E&P capital program heavily weighted to low-risk development drilling in 2011.

* Plan to invest approximately $1.4 billion in the Fayetteville Shale play in 2011.

Note that the information contained on this slide constitutes a "Forward-Looking Statement".

(Slide 8)
Fayetteville Shale Focus Area

This slide contains a map of the Fayetteville Shale Focus Area in Arkansas. Well locations for all wells drilled from inception of the play through September 30, 2011 are indicated on the map by initial production rate in the following ranges: less than or equal to 3MMcf/d, greater than 3MMcf/d and greater than 6MMcf/d. The Mississippi Embayment is also indicated on the map.

* At December 31, 2010, SWN held approximately 916,000 net acres in the Fayetteville Shale play area (equivalent to approximately 1,400 square miles).

* Mississippian-age shale, geological equivalent of the Barnett Shale in north Texas.

* In the first nine months of 2011, SWN placed 418 operated wells on production, all of which were horizontal wells fracture stimulated with slickwater.

* We plan to drill approximately 525-550 operated wells in 2011.

Notes: Rates are AOGC Form 13 and Form 3 test rates.

Note that the information contained on this slide constitutes a "Forward-Looking Statement".

(Slide 9)
Fayetteville Shale – Continuous Improvement

	2007	2008	2009	2010	2011 9M
Days to Drill	17	14	12	11	8
Lateral Length (in feet)	2,657	3,619	4,100	4,528	4,889
Well Cost ($ in millions)	$2.9	$3.0	$2.9	$2.8	$2.8
F&D Cost ($ per Mcfe)	$2.05	$1.21	$0.69	$0.86	
Production (in Bcfe)	53.5	134.5	243.5	350.2	320.4
Reserves (in Bcfe)	716	1,545	3,117	4,345	

* Continuous improvement in our Fayetteville Shale operations.

* Current remaining inventory of over 8,000 net wells on approximately 600,000 net acres drilled to date, greater than 15 years of drilling at current pace.

* Contiguous acreage position allows us economies of scale, vertical integration and operating flexibility.

Note that the information contained on this slide constitutes a "Forward-Looking Statement".

(Slide 10)
Fayetteville Shale - Horizontal Well Performance

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

Note: Data 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.

(Slide 11)
Fayetteville Shale - Horizontal Well Performance

The graph contained in this slide provides average daily production data through September 30, 2011, for the company's horizontal wells drilled in the Fayetteville Shale. This graph displays four composite curves, one composite curve showing the SW/XL normalized production from all the company's horizontal wells and three composite curves showing the results of the company's horizontal wells with laterals greater than 3,000 feet, greater than 4,000 feet, and greater than 5,000 feet. The production data is compared to 2 Bcf, 3 Bcf, and 4 Bcf typecurves from the company's reservoir simulation shale gas model. Well counts and respective days of production are also displayed, as follows:

Days of Production	Total Well Count	Horizontal Wells with Laterals > 3,000 Feet	Horizontal Wells with Laterals > 4,000 Feet	Horizontal Wells with Laterals > 5,000 Feet
0	2,059	1,657	966	305
100	1,952	1,566	903	283
200	1,782	1,372	755	226
300	1,629	1,249	645	169
400	1,463	1,073	521	122
500	1,300	923	401	78
600	1,155	815	330	54
700	1,042	701	253	36
800	943	601	193	22
900	814	501	134	9
1,000	665	357	80	5
1,100	576	261	44	4
1,200	487	201	19	1
1,300	389	122	5	0
1,400	310	65	1	0
1,500	233	22	0	0

Note: Data as of September 30, 2011. Excludes wells with mechanical problems (32).

(Slide 12)
Fayetteville Shale - Gross Production

This slide contains a line graph displaying gross production in MMcf/d for the Fayetteville Shale from January 2006 to October 23, 2011. Gross operated production of approx. 1,874 MMcf/d as of October 23, 2011. 2010 Fayetteville Shale F&D cost of $0.86/Mcf. Periods of production affected by pipeline curtailment issues are denoted.

(Slide 13)
Midstream - Adding Value Beyond the Wellhead

This slide contains a map of several counties in Arkansas where the company's Fayetteville Shale Focus Area is located. These counties include Johnson, Pope, Van Buren, Cleburne, Logan, Yell, Conway, Faulkner and White. Lines trace DeSoto Gathering Lines and the Ozark, Centerpoint, Boardwalk, NGPL, MRT and TETCO transmission pipelines. Compression facilities are also indicated on the map.

* Midstream assets provide rapidly growing revenue stream and potential future funding source.

* At October 27, 2011, gathering approximately 2.0 Bcf per day through 1,745 miles of gathering lines, up from approximately 1.7 Bcf per day the same time a year ago.

* Midstream EBITDA (1) of $220.5 million in 2010. Projected EBITDA for 2011 of approximately $275-$280 million.

* Phase 1 Fayetteville Lateral of Boardwalk Pipeline placed in-service December 2008 (FT volumes of 800,000 MMBtu/d on Fayetteville Lateral and 640,000 MMBtu/d on Greenville Lateral).

* Fayetteville Express Pipeline placed in-service October 2010 (FT volumes of 1,200,000 dkth/d).

Note: Map as of September 30, 2011.

(1) EBITDA is a non-GAAP financial measure. See explanation and reconciliation of EBITDA on page 36.

Note that the information contained on this slide constitutes a "Forward-Looking Statement".

(Slide 14)
Marcellus Shale

This slide contains a map of several counties in Pennsylvania and New York and certain well production data. The company's acreage positions are highlighted. The locations of the company's test wells are shown on the map: Greenzweig, Range Trust, Price and Lycoming. Lines trace the Transco, Tennessee Gas, Millennium and Stagecoach transmission pipelines.

* At December 31, 2010, SWN held approximately 173,000 net acres in Northeast Pennsylvania.

* Currently running 2 operated rigs and plan to participate in 35 operated Marcellus wells in 2011. The company plans to increase its drilling activity in 2012 with 4-5 operated rigs.

* At September 30, 2011, we had 17 operated Marcellus Shale horizontal wells on production in our Greenzweig area in Bradford County. Daily gross operated production was approximately 110 MMcf per day.

Note that the information contained on this slide constitutes a "Forward-Looking Statement".

(Slide 15)
Marcellus Shale - Horizontal Well Performance

The graph contained in this slide provides average daily production data through September 30, 2011, for the company's horizontal wells drilled in the Marcellus Shale. This graph displays a composite curve showing the results of the company's horizontal wells with 15 or more stages (2 wells), 10 to 14 stages (8 wells), and 9 or less stages (7 wells). The production data is compared to 8 Bcf, 6 Bcf, and 4 Bcf typecurves from the company's reservoir simulation shale gas model.

Days of Production	Total Well Count
0	17
50	17
100	17
150	12
200	10
250	7
300	3
350	1
400	1

Notes: Data as of September 30, 2011.

(Slide 16)
New Ventures – Brown Dense Project

This slide displays the Lower Smackover Brown Dense play, located on the border of Arkansas and Louisiana, in comparison to East Texas, Arkoma Basin, and Fayetteville Shale plays. The map of the Lower Smackover Brown Dense highlights the following oil fields: Wesson, McKamie-Patton, Walker Creek, Dorcheat-Macedonia, Atlanta, Magnolia, Shuler, Lisbon, El Dorado, Shadow Bend, Champagnolle, Smackover, and Ora. The map also highlights the following gas fields: Rodessa, Shangaloo-Red Rock, and Monroe. Included in the Lower Smackover Brown Dense map is the location of SWN’s first well to be drilled in Columbia County, Arkansas

* SWN currently holds 487,000 net acres in Lower Smackover Brown Dense play. Total land cost of $150 million; 82% NRI; leases have 4-year terms and 4-year extensions.

* Targeting Upper Jurassic age, kerogen-rich carbonate in Southern Arkansas and Northern Louisiana with horizontal drilling.

* Expect to complete our first well in Arkansas in November. Plan to spud our second well in November.

Note that the information contained on this slide constitutes a "Forward-Looking Statement".

(Slide 17)
New Ventures – New Brunswick, Canada Project

This slide contains a map of the Province of New Brunswick, Canada. The acreage on which the company has obtained licenses to explore is highlighted on the map: Marysville (2,309,247 acres) and Cocagne (209,271 acres). The McCully Field, Stoney Creek Field, M&NE Pipeline and the Green Road G-41 Well are denoted on the map. The 2010 2D Seismic Test locations of Doaktown and Killams Mills are also denoted on the map.

* SWN currently holds exploration licenses to over 2.5 million acres within the Maritimes Basin

* Principal targets are the conventional and unconventional sandstone and shale reservoirs of the Horton Group (Frederick Brook Shale)

* Oil and gas production from fields along southern flank:
    * McCully - reserves 190 bcfg
    * Stoney Creek - cum 800,000 bo, 30 bcfg

* 3-year initial exploration license to complete work program
    * $47MM total work commitment with options for multiple 5-year extension leases
    * $10.7 MM invested in 2010; $14.2 MM investment planned for 2011
    * Maximum 12.5% royalty

Note that the information contained on this slide constitutes a "Forward-Looking Statement".

(Slide 18)
Outlook for 2011

*** Production target of 496-500 Bcfe in 2011 (estimated growth of 23%).**

	2010 Actual	2011 Guidance NYMEX Price Assumption	
	$4.39 Gas	$4.00 Gas	$4.25 Gas
	$77.32 Oil	$90.00 Oil	$90.00 Oil
Net Income	$604.1 MM	$605-$615 MM	$615-$625 MM
Diluted EPS	$1.73	$1.73-$1.76	$1.76-$1.79
EBITDA (1)	$1,612.3 MM	$1,765-$1,775 MM	$1,775-$1,785 MM
Net Cash Flow (1)	$1,579.7 MM	$1,745-$1,755 MM	$1,755-$1,765 MM
CapEx	$2,120 MM	$2,000 MM	$2,000 MM
Debt %	27%	26%-27%	26%-27%

(1) Net cash flow is net cash flow before changes in operating assets and liabilities. Net cash flow and EBITDA are non-GAAP financial measures. See explanation and reconciliation of non-GAAP financial measures on pages 34 and 36.

Note that the information contained on this slide constitutes a "Forward-Looking Statement".

(Slide 19)
The Road to V +

* Invest in the Highest PVI Projects.

* Flexibility in 2011 Capital Program.

* Maintain Strong Balance Sheet.

* Deliver the Numbers.
    * Production and Reserves.
    * Maximize Cash Flow.

* Continue to Tell Our Story.

Note that the information contained on this slide constitutes a "Forward-Looking Statement".

(Slide 20)
Appendix

(Slide 21)

Financial & Operational Summary

	Nine Months Ended Sept. 30,		Year Ended December 31,		
	2011	2010	2010	2009	2008
	($ in millions, except per share amounts)				
Revenues	$2,208.8	$1,940.2	$2,610.7	$2,145.8	$2,311.6
EBITDA (1)	1,325.4	1,199.3	1,612.3	1,368.1 (3)	1,362.3 (2)

Adjusted Net Income	479.2	454.6	604.1	522.7 (3)	567.9 (2)
Net Cash Flow (1)	1,312.3	1,184.6	1,579.7	1,441.0	1,167.5
Adjusted Diluted EPS	$1.37	$1.30	$1.73	$1.52 (3)	$1.64 (2)
Diluted CFPS (1)	$3.75	$3.39	$4.52	$4.13	$3.37
Production (Bcfe)	366.7	293.3	404.7	300.4	194.6
Avg. Gas Price ($/Mcf)	$4.24	$4.76	$4.64	$5.30	$7.52
Avg. Oil Price ($/Bbl)	$93.54	$75.39	$76.84	$54.99	$107.18
Finding Cost ($/Mcfe) (4)			$1.02	$0.86	$1.53
Reserve Replacement (%) (4)			430%	592%	523%

(1) Net cash flow is net cash flow before changes in operating assets and liabilities. Net cash flow, EBITDA and diluted CFPS are non-GAAP financial measures. See explanation and reconciliation of non-GAAP financial measures on pages 34 and 36.
(2) Adjusted net income and adjusted diluted EPS for 2008 includes after-tax gain on sale of utility assets of $35.4 million ($0.10 per diluted share) during the third quarter of 2008 (while EBITDA includes the pre-tax gain on sale of $57.3 million).
(3) Adjusted net income and adjusted diluted EPS in 2009 exclude a $558.3 million after-tax non-cash ceiling test impairment and both are non-GAAP financial measures (while EBITDA excludes the pre-tax non-cash ceiling test impairment of $907.8 million). See explanation and reconciliation of adjusted net income and adjusted diluted EPS on page 35.
(4) Includes reserve revisions and excludes capital investments in our sand facility, drilling rig related and ancillary equipment.

(Slide 22)
Gas Hedges in Place Through 2013

This slide contains a bar chart detailing gas hedges in place by quarter for year 2011, year 2012 and year 2013. A summary of these gas hedges is as follows:

	Type	Hedged Volumes	Average Price per Mcf (or Floor/Ceiling)	Percent Hedged
2011	Swaps	196.5 Bcf	$5.29	40%
	Collars	62.1 Bcf	$5.09 / $6.50	13%
2012	Swaps	185.2 Bcf	$5.02	-
	Collars	80.5 Bcf	$5.50 / $6.67	-
2013	Swaps	185.2 Bcf	$5.06	-

Note that the information contained on this slide constitutes a "Forward-Looking Statement".

(Slide 23)
SWN is One of the Lowest Cost Operators

This slide contains a bar graph that compares SWN to its competitors in terms of Lifting Cost per Mcfe of production (3 year average).

	Lifting Cost per Mcfe Of Production (3 year average)
Southwestern Energy Company	**$0.94**
Ultra Petroleum	$1.00
Noble Energy	$1.07
EOG Resources	$1.09
Range Resources	$1.10
Forest Oil	$1.12
Chesapeake Energy	$1.15
Cabot Oil & Gas	$1.32
Anadarko Petroleum	$1.48
Sandridge Energy	$1.49
Newfield Exploration	$1.54
Devon Energy	$1.54
Cimarex Energy	$1.63
Occidental Petroleum	$1.68
SM Energy	$1.82

Pioneer Natural Resources	$1.90
Apache	$1.99
Denbury Resources	$3.69

This slide also contains a bar graph comparing SWN to its competitors in terms of Finding & Development Cost per Mcfe (3 year average).

	Finding & Development Cost per Mcfe (3 year average)
Southwestern Energy Company	**$1.07**
Range Resources	$1.27
Ultra Petroleum	$1.68
Cabot Oil & Gas	$1.95
EOG Resources	$2.04
Noble Energy	$2.16
Denbury Resources	$2.47
Devon Energy	$2.59
Occidental Petroleum	$2.72
Pioneer Natural Resources	$2.73
Newfield Exploration	$2.79
Forest Oil	$2.86
Sandridge Energy	$2.87
Chesapeake Energy	$2.97
Cimarex Energy	$2.98
Anadarko Petroleum	$2.99
Apache	$3.84
SM Energy	$5.08

Source: Public filings
Note: All data as of December 31, 2008, 2009, and 2010.
Lifting Cost per Mcfe defined as lease operating expenses plus production taxes divided by production.
F&D Cost per Mcfe defined as the three-year sum of costs incurred in natural gas and oil exploration and development divided by the three-year sum of reserve additions from extensions and discoveries, improved recovery, revisions and purchases.

(Slide 24)
Fayetteville Shale Production Compared to the Barnett

The graph contained in this slide displays production volumes in MMcf/d for the Fayetteville Shale over a more than 6-year period and the Barnett Shale over a more than 27-year period. Total Fayetteville Shale Field average daily production for July 2011 was 2,597 MMcf/d.

A box accompanying the graph states:
We collapsed the “learning curve” dramatically; Paradigm shift in gas prices

Source: Tudor, Pickering, Holt & Co. Securities, Inc., Arkansas Oil & Gas Commission

(Slide 25)
Fayetteville Shale Activity Compared to the Barnett

This slide contains bar charts displaying the number of wells drilled in the Barnett Shale Play and the Fayetteville Shale Play, summarized as follows:

Barnett Shale Play
*1981 – 1 st Well Drilled
*1992 – 1 st Horizontal Well Drilled
*1997 – 1 st Slickwater Frac
1981-1989 Avg. 7 Vertical Wells/Year

1990-1994	Avg. 28 Vertical Wells/Year	
1995-1999	Avg. 75 Vertical Wells/Year	
2000	Vertical Wells Drilled	165
	Horizontal Wells Drilled	0
2001	Vertical Wells Drilled	408
	Horizontal Wells Drilled	1
2002	Vertical Wells Drilled	669
	Horizontal Wells Drilled	2
2003	Vertical Wells Drilled	663
	Horizontal Wells Drilled	70
2004	Vertical Wells Drilled	524
	Horizontal Wells Drilled	260
2005	Vertical Wells Drilled	351
	Horizontal Wells Drilled	701
2006	Vertical Wells Drilled	276
	Horizontal Wells Drilled	1,214
2007	Vertical Wells Drilled	178
	Horizontal Wells Drilled	2,117
2008	Vertical Wells Drilled	145
	Horizontal Wells Drilled	2,508
2009	Vertical Wells Drilled	54
	Horizontal Wells Drilled	1,586
2010	Vertical Wells Drilled	65
	Horizontal Wells Drilled	1,643

<u>Fayetteville Shale Play</u>

*Q2 2004 – 1 st Well Drilled
*Q1 2005 – 1 st Horizontal Well Drilled
*Q3 2005 – 1 st Slickwater Frac

2004	Vertical Wells Drilled	14
	Horizontal Wells Drilled	0
2005	Vertical Wells Drilled	37
	Horizontal Wells Drilled	13
2006	Vertical Wells Drilled	12
	Horizontal Wells Drilled	103
2007	Vertical Wells Drilled	13
	Horizontal Wells Drilled	419
2008	Vertical Wells Drilled	14
	Horizontal Wells Drilled	690

2009	Vertical Wells Drilled	2
	Horizontal Wells Drilled	858
2010	Vertical Wells Drilled	0
	Horizontal Wells Drilled	653

Source: Republic Energy Co., PI-Dwights (IHS Energy), Southwestern Energy

(Slide 26)
Water Demand: Perspective

The graphs contained in this slide compare the daily statewide demand for water in Arkansas by source to the average daily amount used by Southwestern Energy by source.

Statewide Demand:
11,500 million gallons/day
33% Ground Water
66% Surface Water

SWN Operations Demand:
10 million gallons/day (600 Wells/year)
20% Recycle/Reused Water SGW, FBW, & PW
80% Surface Water

A box accompanying the graphs states:
SWN Operations Less than 0.09% of State's water demand
Source: U.S. Geological Survey, Central Arkansas Water, Southwestern Energy Company estimates.
Shallow Ground Water (SGW) – Ground water recovered from shallow formations during the air drilling process.
Flow Back Water (FBW) – Frac Fluid that is recovered from the well after the fracture stimulation.
Produced Water (PW) – Natural formation water that is returned to the surface throughout the producing life of the well.

(Slide 27)
Drilling & Completion Major Cost Categories
Average 2011 Fayetteville Shale Well Cost Estimate

This slide displays the estimated average 2011 major well cost categories as a proportion to the total average well costs.

	Average 2011 Fayetteville Shale Well Costs (in thousands)
Fracture Stimulation	**$780**
Rig	**390**
OCTG	**300**
Drilling Fluids	130
Directional Drilling	120
Other	116
Wireline	120
Location	100
Water Treatment/Disposal	100
Supervision	89
Rentals	84
Trucking & Transportation	69
Wellhead & Surface Equipment	54
Bits	55

Coil Tubing	55
Environmental & Restoration	49
Surface Rentals	49
D&C Fluids	44
Special Services	40
Cementing	24
Fuel & Water	24
Land & Damages	19
Formation Evaluation	14
Major Cost Categories	**$2,825**

(Slide 28)
ArkLaTex Division

This slide contains a map of the ArkLaTex Division, which is composed of East Texas and Arkoma Basin, in relation to Texas, Oklahoma, Arkansas, and Louisiana. The slide also contains two graphs outlining the production, capital expenditures, and reserves for East Texas and Arkoma Basin for the period extending from 2000 to 2010, summarized as follows:

Arkoma Basin

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Production (Bcfe)	19.9	22.3	19.8	18.9	20.1	20.2	20.1	23.8	24.4	22	19.2
Reserve (Bcfe)	200.3	186	188.7	211.7	239.5	271	277	304	281	208	226
Capex (in millions)	$ 17.6	$ 28.6	$ 18.2	$ 32.9	$ 53.2	$ 64.5	$ 97.0	$ 148.0	$ 133.0	$ 40.0	$ 13.0

East Texas

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Production (Bcfe)	0.3	2.3	5.9	13.6	22.2	28.2	32	29.9	31.6	34.9	34.3
Reserve (Bcfe)	22	57.6	111	196.3	299.1	368.7	383	353	351	330	328
Capex (in millions)	$ 6.1	$ 30.9	$ 33.6	$ 97.3	$ 156.7	$ 183.6	$ 204.0	$ 201.0	$ 160.0	$ 167.0	$ 150.0

Arkoma Basin
Acreage: 308,123 net acres (at 12/31/10)
2010 Reserves: 226 Bcf (4% of total)
2010 Production: 19.2 Bcf (5% of total)

East Texas
Acreage: 125,563 net acres (at 12/31/10)
2010 Reserves: 328 Bcf (7% of total)
2010 Production: 34.3 Bcf (8% of total)

Note: Conventional Arkoma acreage excludes 124,986 net acres in the conventional Arkoma Basin operating area that are also within the company's Fayetteville Shale focus area.

(Slide 29)

U.S. Gas Consumption and Sources

This slide displays U.S. dry gas production versus U.S. gas consumption in Bcf from 1975 to present. Net imports for the same period are also given. U.S. gas production rising in recent years.

Source: EIA

(Slide 30)
U.S. Electricity Consumption

This line graph shows U.S. electricity consumption in billion kilowatt-hours per month from 1990 to present.

Source: Edison Electric Institute

(Slide 31)
U.S. Electricity Generation

This slide contains a chart showing Electricity Generation by Energy Source as a percentage of total.

Total 4,120 Billion kWh in 2010.

Energy Source	% of Total Electricity Generation
Coal	44.9%
Natural Gas	23.8%
Nuclear	19.6%
Hydroelectric	6.1%
Other Renewables	4.1%
Petroleum	0.9%
Other Gases	0.3%
Other	0.3%

Source: EIA

Additionally, this slide contains a chart displaying a comparison of Electricity Generation Capacities in 2009 compared to Electricity Generated in 2010.

While coal and nuclear power plants operate at very high capacity, natural gas power plants are only running at 24% of their capacity.

	2010 Generation	2009 Capacity *	Unused Capacity
Natural Gas	112,079	430,697	76%
Coal	211,273	333,035	38%
Nuclear	92,120	105,764	14%

*Excludes standby units
Source: EIA

(Slide 32)
U.S. Gas Drilling and Prices

This line graph denotes the number of rigs drilling for gas and the gas price in dollars per MMBtu through the period 2000 to present.

Source: Baker Hughes, Bloomberg

(Slide 33)
Oil and Gas Price Comparison

This line graph compares the prices of Henry Hub natural gas and WTI crude oil in $/MMBtu and $/Bbl, respectively, for the period 1994 to present.

Source: Bloomberg

(Slide 34)
Explanation and Reconciliation of Non-GAAP Financial Measures: Net Cash Flow

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 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 flow. 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. These adjusted amounts are not a measure of financial performance under GAAP.

	9 Months Ended September 30,		**12 Months Ended December 31,**		
	2011	**2010**	**2010**	**2009**	**2008**
	(in thousands)		(in thousands)		
Net cash provided by operating activities	$1,300,211	$1,215,062	$1,642,585	$1,359,376	$1,160,809
Add back (deduct):					
Change in operating assets and liabilities	12,129	(30,507)	(62,906)	81,652	6,685

Net cash flow	$1,312,340	$1,184,555	$1,579,679	$1,441,028	$1,167,494

	2011 Guidance	
	NYMEX Commodity Price Assumption	
	$4.00 Gas $90.00 Oil	$4.25 Gas $90.00 Oil
	($ in millions)	
Net cash provided by operating activities	$1,745 - $1,755	$1,755-$1,765
Add back (deduct):		
Assumed change in operating assets and liabilities	--	--
Net cash flow	$1,745 - $1,755	$1,755-$1,765

Note that the information contained on this slide constitutes a "Forward-Looking Statement".

(Slide 35)
Explanation and Reconciliation of Non-GAAP Financial Measures: Adjusted Net Income

Additional non-GAAP financial measures we may present from time to time are net income attributable to Southwestern Energy and diluted earnings per share attributable to Southwestern Energy stockholders, both of 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.

	12 Months Ended December 31, 2009	
	($ in thousands)	(per share)
Net loss attributable to SWN	$(35,650)	$(0.10)
Add back:		
Impairment of natural gas & oil properties (net of taxes)	558,305	1.62
Adjusted net income	$522,655	$1.52

(Slide 36)
Explanation and Reconciliation of Non-GAAP Financial Measures: EBITDA

EBITDA is defined as net income plus interest, income tax expense, depreciation, depletion and amortization. Southwestern has included information concerning EBITDA because it is used by certain investors as a measure of the ability of a company to service or incur indebtedness and because it is a financial measure commonly used in the energy industry. EBITDA should not be considered in isolation or as a substitute for net income, net cash provided by operating activities or other income or cash flow data prepared in accordance with generally accepted accounting principles or as a measure of the company's profitability or liquidity. EBITDA as defined above may not be comparable to similarly titled measures of other companies. Net income is a financial measure calculated and presented in accordance with generally accepted accounting principles. The table below reconciles historical EBITDA with historical net income.

	9 Months Ended September 30,		12 Months Ended December 31,										
	2011	2010	2010	2009 (1)	2008	2007	2006	2005	2004	2003	2002	2001	2000
	($ in thousands)												
Net income (loss) attributable to SWN	$479,263	$454,607	$604,118	$(35,650) (2)	$ 567,946	$ 221,174	$ 162,636	$ 147,760	$ 103,576	$ 48,897	$ 14,311	$ 35,324	$20,461 (6)
Add back:													
Net interest expense	19,263	19,277	26,163	18,638	28,904	23,873	679	15,040	16,992	17,311	21,466	23,699	24,689
Provision (benefit) for income taxes	312,733	291,116	391,659	(16,363) (3)	350,999	135,855	99,399	86,431	59,778	28,372 (5)	8,708	21,917	11,457
Depreciation, depletion and amortization	514,180	434,307	590,332	1,401,470 (4)	414,460	294,500	151,795	96,641	74,919	56,833	54,095	53,003	47,505
EBITDA	$1,325,412	$1,199,307	$1,612,272	$1,368,095	$1,362,309	$ 675,402	$ 414,509	$ 345,872	$ 255,265	$ 151,413	$ 98,580	$ 133,943	$104,112 (6)

(1) Net income for the Midstream Services segment was $105,636 depreciation, depletion and amortization was $28,765, net interest expense was $18,275 and provision for income taxes was $67,834.
(2) Net income (loss) includes the after tax $558.3 million non-cash ceiling impairment of our natural gas and oil properties recorded in Q1 2009.
(3) Provision (benefit) for income taxes includes the ($349.5) million income tax benefit related to the non-cash ceiling impairment of our natural gas and oil properties recorded in Q1 2009.

(4) Depreciation, depletion and amortization includes the $907.8 million non-cash ceiling impairment of our natural gas and oil properties recorded in Q1 2009.
(5) Provision for income taxes for 2003 includes the tax benefit associated with the cumulative effect of adoption of accounting principle.
(6) 2000 amounts exclude unusual items of $109.3 million for the Hales judgment and $2.0 million for other litigation.

The table below reconciles forecasted EBITDA with forecasted net income for 2011, assuming various NYMEX price scenarios and the corresponding estimated impact on the company's results for 2011, including current hedges in place:

	2011 Guidance		
	Overall Corporate		
	NYMEX Commodity Price Assumption		Midstream Services Segment (1)
	$4.00 Gas $90.00 Oil	$4.25 Gas $90.00 Oil	
	($ in millions)		
Net income attributable to SWN	$605-$615	$615-$625	$130-$135
Add back:			
Provision for income taxes	403-410	410-417	84-87
Interest expense	26-28	26-28	22-23
Depreciation, depletion and amortization	715-720	715-720	36-38
EBITDA	$1,765-$1,775	$1,775-$1,785	$275-$280

(1) Midstream Services segment results assume NYMEX commodity prices of $4.00 per Mcf for natural gas and $90.00 per barrel for crude oil for 2011.

Note that the information contained on this slide constitutes a "Forward-Looking Statement".