



SWN
Southwestern Energy®

May 2013 Update

NYSE: SWN

• General Information •

Southwestern Energy Company is an independent 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 May 1, 2013 •

NYSE: SWN

Shares of Common Stock Outstanding – 351,522,140

Market Capitalization – \$12,841,000,000

Institutional Ownership – 91.6%

Management and Board Ownership – 2.0%

52-Week Price Range – \$25.82 (6/13/12) – \$39.26 (4/11/13)

• Investor Contacts •

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Forward-Looking Statements



All statements, other than historical facts and financial information, may be deemed to be forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements that address activities, outcomes and other matters that should or may occur in the future, including, without limitation, statements regarding the financial position, business strategy, production and reserve growth and other plans and objectives for the company's future operations, are forward-looking statements. Although the company believes the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance and actual results or developments may differ materially from those in the forward-looking statements. The company has no obligation and makes no undertaking to publicly update or revise any forward-looking statements. 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 May 2, 2013.

About Southwestern



- **Focused on exploration and production of natural gas.**
 - *4.0 Tcfe of reserves; 7.1 R/P at year-end 2012.*
- **E&P strategy built on organic growth through the drillbit.**
 - *Approximately 75% of planned E&P capital allocated to drilling in 2013.*
- **Track record of adding significant reserves at low costs.**
 - *From 2007 to 2012, we've averaged 38% annual production growth and 23% reserve growth and annually replaced over 325% of our production at an F&D cost of \$1.36 per Mcfe⁽¹⁾.*
- **Strategy built on the Formula:**

$$\frac{R^2}{A} \rightarrow V^+$$

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

(1) Reserve replacement ratio and finding and development costs exclude reserve revisions and capital investments in our sand facility, drilling rig related and ancillary equipment.

$$\frac{R^2}{A} \rightarrow V^+$$

First Quarter 2013 Highlights



- First Quarter 2013 Highlights

- *Production up 11%, due to strong Fayetteville and Marcellus results.*
- *Recorded highest first quarter cash flow in company history, primarily driven by low cash operating costs⁽¹⁾ and the continued strong growth from our Midstream business.*
- *Currently drilling on 3 New Ventures ideas – the Lower Smackover Brown Dense formation in southern Arkansas and northern Louisiana, the Marmaton/Atoka oil play in Colorado and the Bakken/Three Forks play in Montana.*
- *Strong balance sheet and financial position as of March 31, 2013:*
 - *Debt-to-book capitalization ratio of 36%.*
 - *\$1.5 billion revolving credit facility with \$35 million drawn.*
 - *Cash and restricted cash on hand of approximately \$25 million.*

- Strong Growth and Low-Cost Operations Set the Stage for a Record 2013

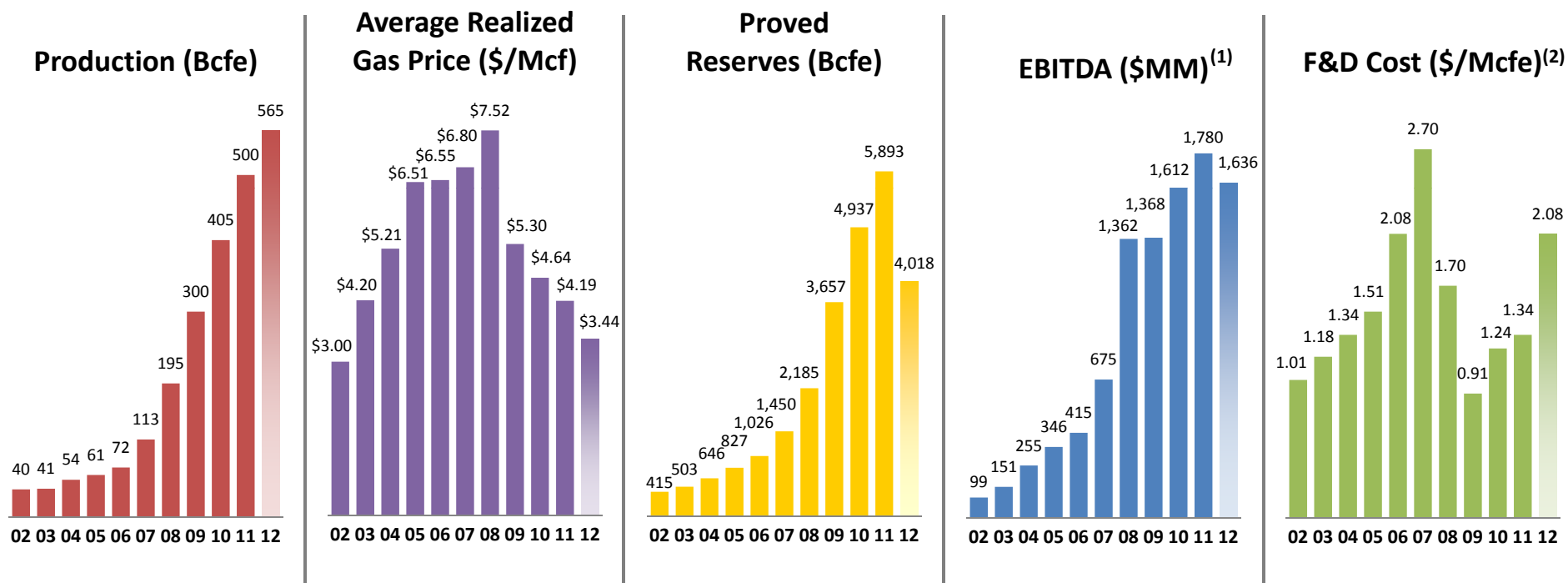
- *2013 projected capital investment program of \$2.0 billion.⁽²⁾*
- *2013 production projected to grow 13%.*

(1) Cash operating costs for the three months ended March 31, 2013, include lease operating expenses (\$0.81/Mcfe), general and administrative expenses (\$0.21/Mcfe), taxes other than income taxes (\$0.12/Mcfe) and net interest expense (\$0.04/Mcfe).

(2) Excludes the pending acquisition of properties in the Marcellus Shale announced in April 2013.

Proven Track Record

For the Periods Ended December 31

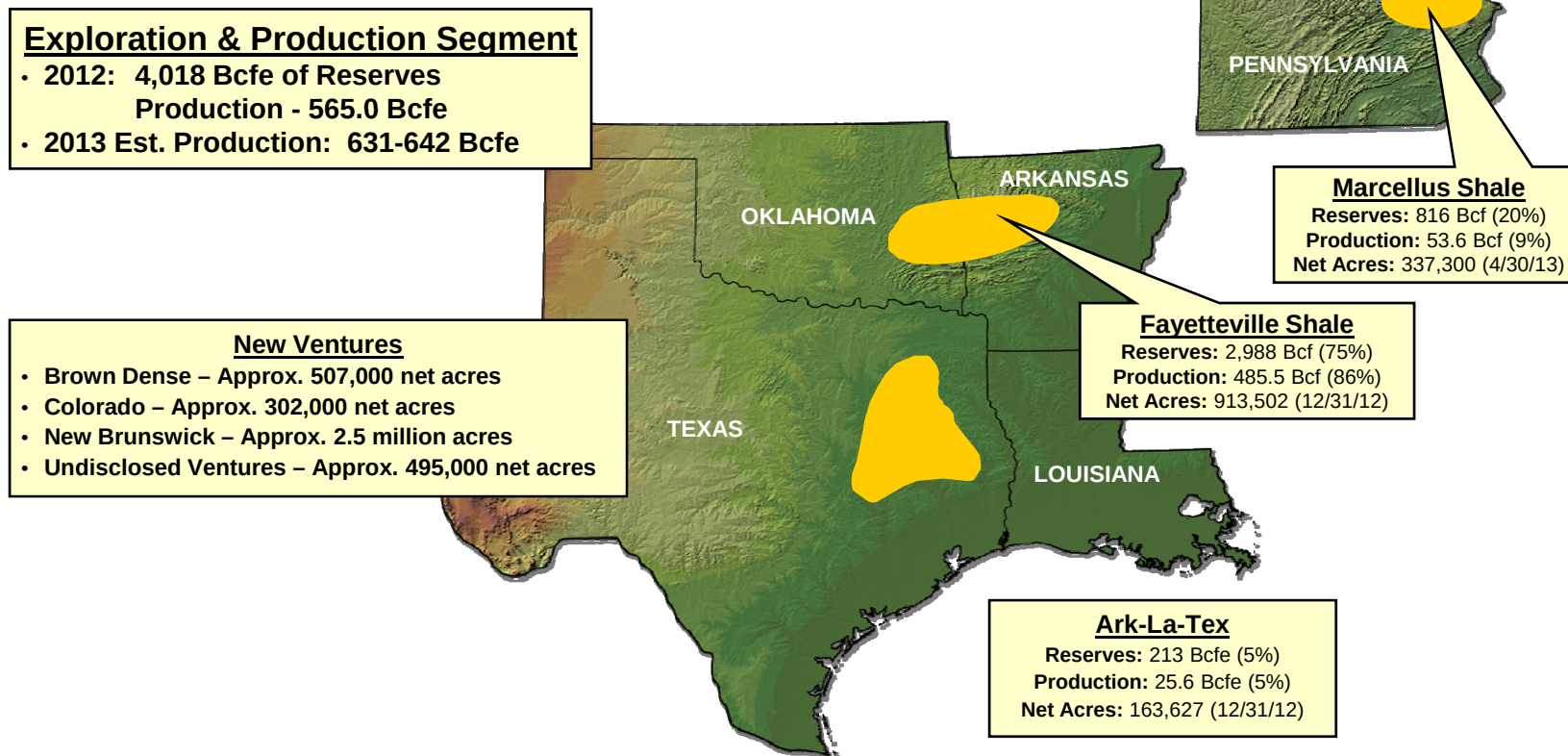


Note: Reserve data includes reserve revisions.

(1) EBITDA is a non-GAAP financial measure. See explanation and reconciliation of EBITDA on page 35.

(2) Excludes reserve revisions and excludes capital investments in our sand facility, drilling rig related and ancillary equipment.

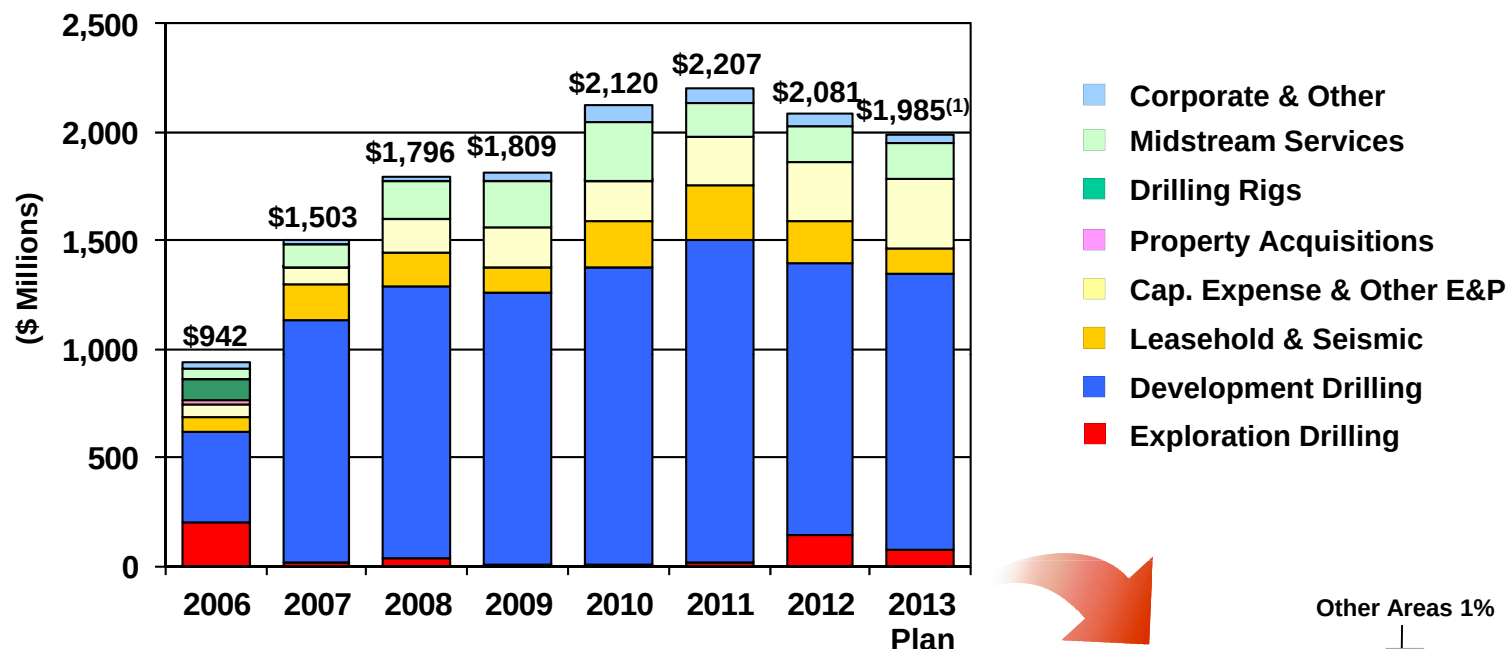
Areas of Operations



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

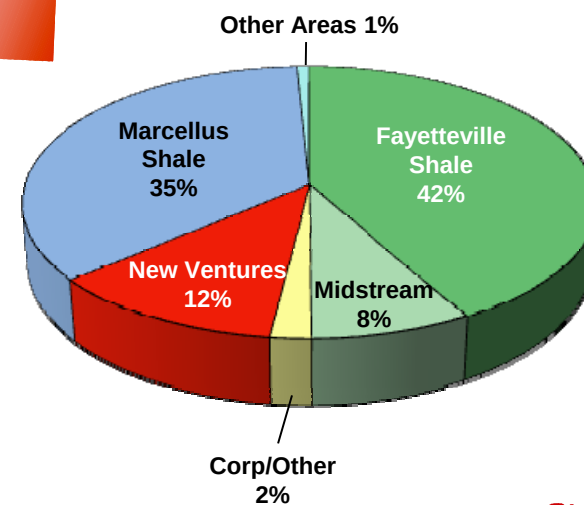
Notes: ArkLaTex acreage excludes 124,653 net acres in the conventional Arkoma Basin operating area that are also within the company's Fayetteville Shale focus area.
Reserves and acreage as of December 31, 2012. Production is a total annual amount for 2012.

Capital Investments

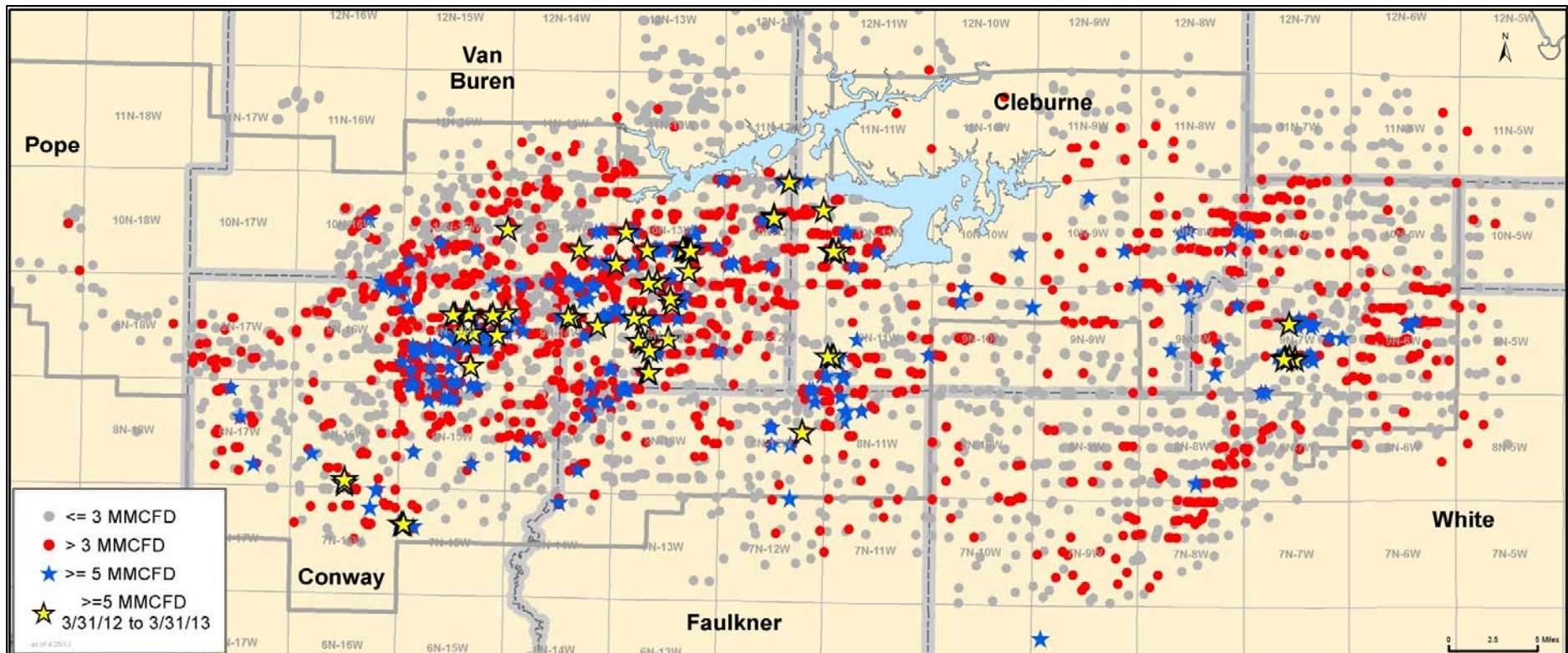


- E&P capital program heavily weighted to low-risk development drilling in 2013.
- Plan to invest approximately \$900 million in the Fayetteville Shale and \$800 million in the Marcellus Shale (including Midstream) in 2013.

(1) Excludes the pending acquisition of properties in the Marcellus Shale announced in April 2013.



Fayetteville Shale Focus Area



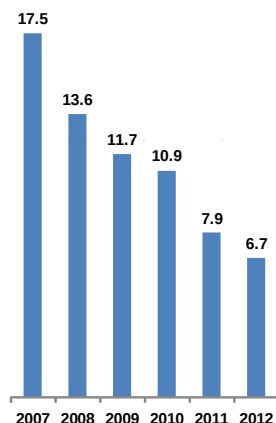
- SWN holds approx. 914,000 net acres in the Fayetteville Shale play (approx 1,400 sq. miles).
- Mississippian-age shale, geological equivalent of the Barnett Shale in north Texas.
- SWN discovered the Fayetteville Shale and has first mover advantage – average acreage cost of \$313 per acre with a 15% royalty and average working interest of 74%.
- We plan to drill approximately 385 to 390 operated wells in 2013.

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

Fayetteville Shale – Continuous Improvement

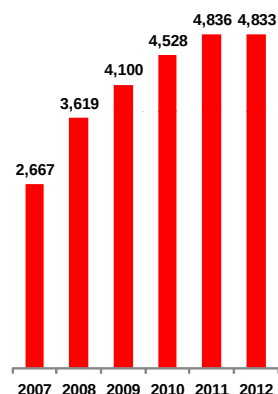
-62%

Days to Drill



+82%

Lateral Length (feet in length)



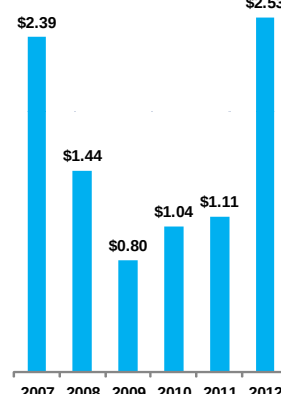
-14%

Well Cost (\$ in millions)

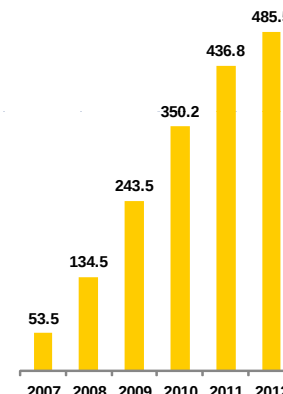


+807%

F&D Cost (\$ per Mcf)

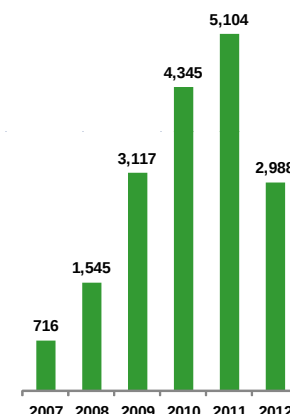


Production (in Bcf)



+317%

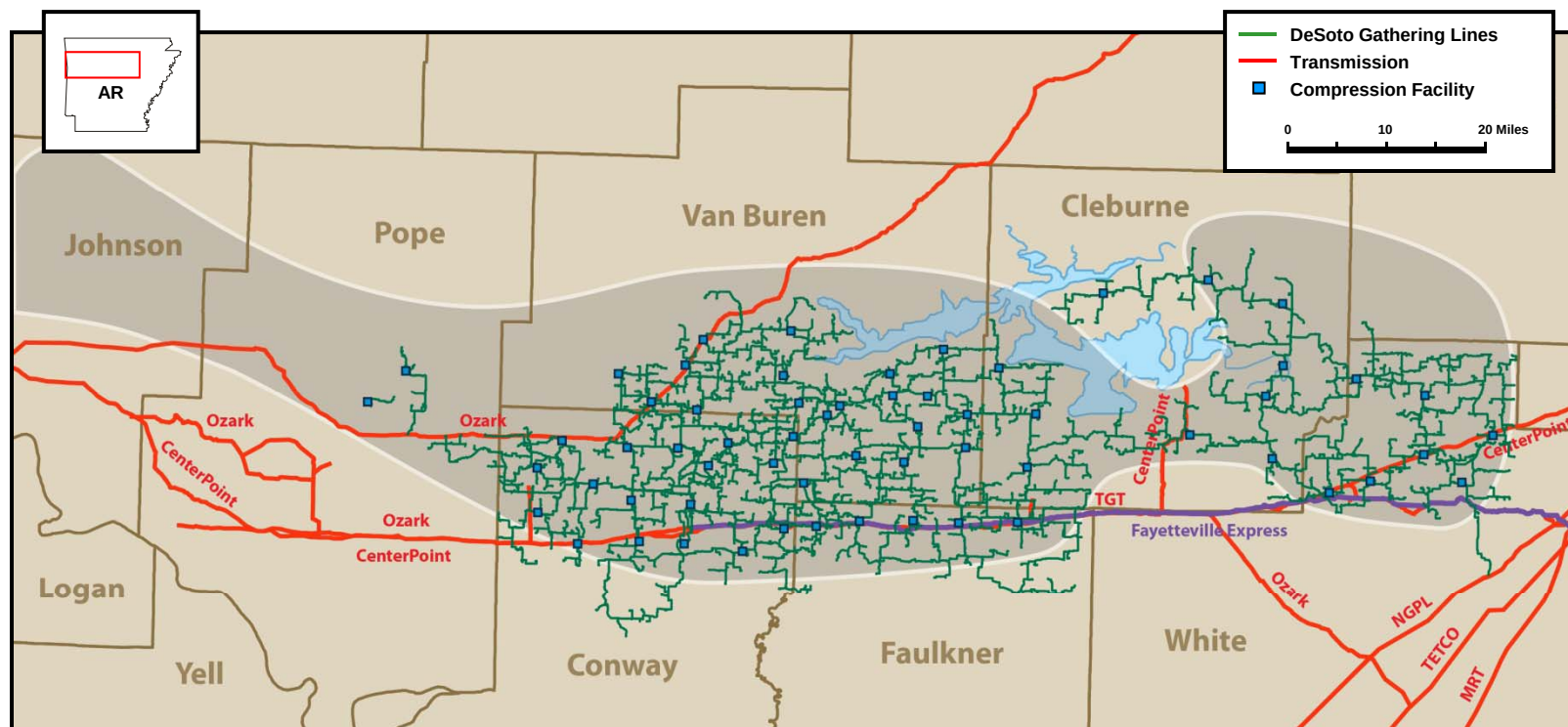
Reserves (in Bcf)



- Continuous improvement in our Fayetteville Shale operations – completed lateral length has increased 82% over the last four years while total well costs have decreased 14%.
- Vertical integration and contiguous acreage position allow us significant economies of scale and operating flexibility.

Note: Finding and development costs exclude revisions and capital investments in our sand facility, drilling rig related and ancillary equipment.

Midstream - Adding Value Beyond the Wellhead

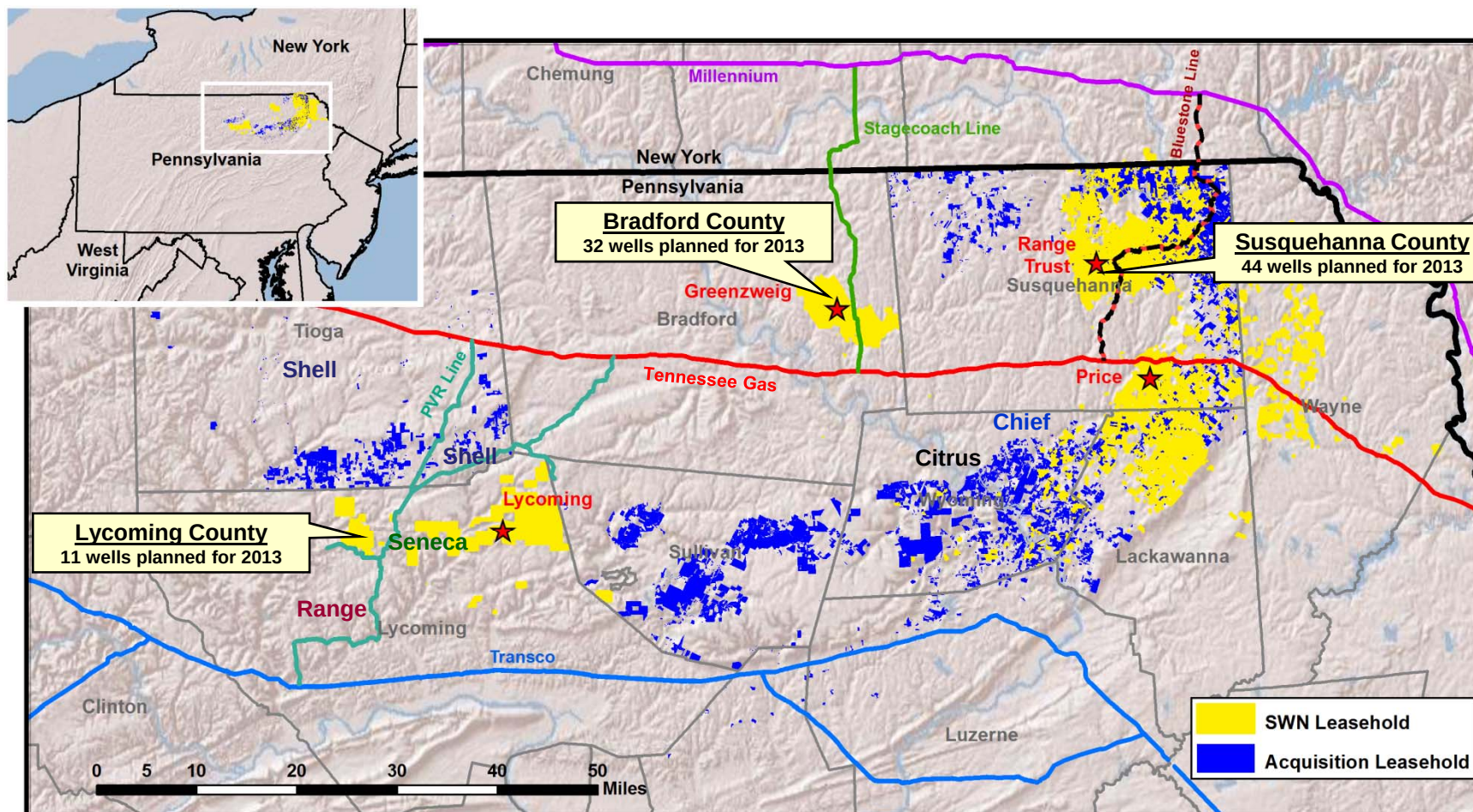


- SWN's Fayetteville Shale gathering system is one of the largest in the U.S.
- At March 31, 2013, gathering approximately 2.2 Bcf per day through 1,859 miles of gathering lines and 531,000 horsepower of compression equipment.
- SWN has total firm transportation for the Fayetteville Shale of 2.0 Bcf per day.
- 2012 EBITDA⁽¹⁾ of \$338.8 million; projected EBITDA of \$355-\$360 million in 2013.

Note: Map as of March 31, 2013.

(1) EBITDA is a non-GAAP financial measure. See explanation and reconciliation of EBITDA on page 35.

Marcellus Shale



- We hold approximately 337,300 net acres⁽¹⁾ in Northeast Pennsylvania.
- Agreed to purchase approximately 162,000 net acres in April 2013 for \$93 million. Expected to close May 2013.
- On March 31, 2013, gross operated production was approximately 359 MMcf/d from 92 operated horizontal wells.
- We plan to drill up to 86 to 88 operated wells in 2013.

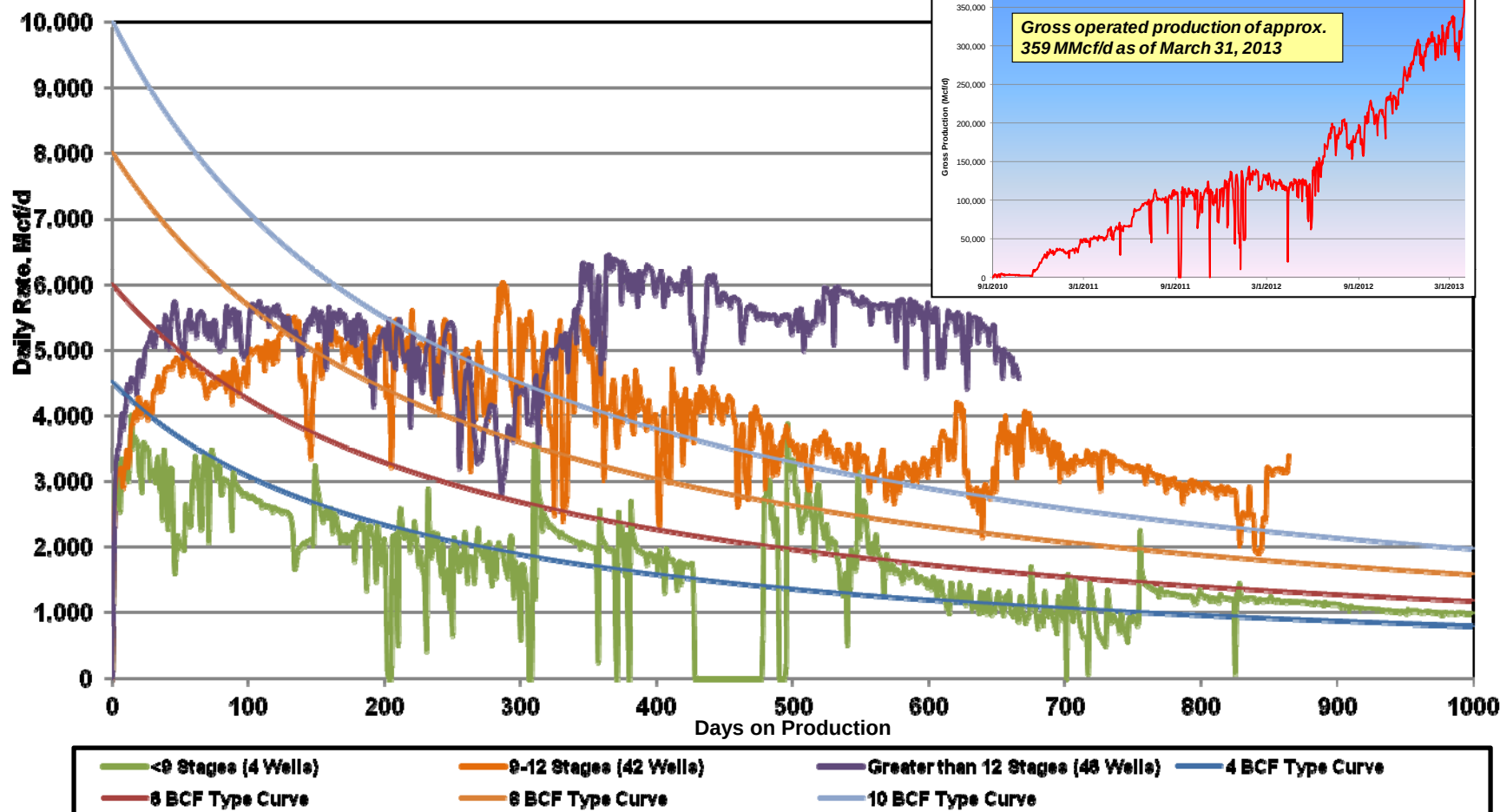
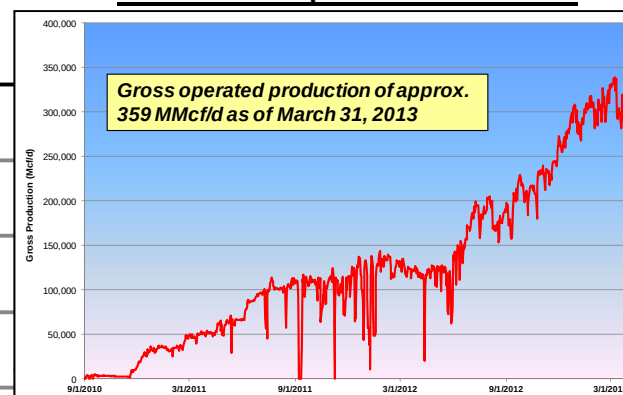
(1) Includes acreage we have agreed to purchase on April 29, 2013.

Forward-Looking Statement

$\frac{R^2}{A} \rightarrow V^+$

Marcellus Shale – Horizontal Well Performance

SWN Gross Operated Production

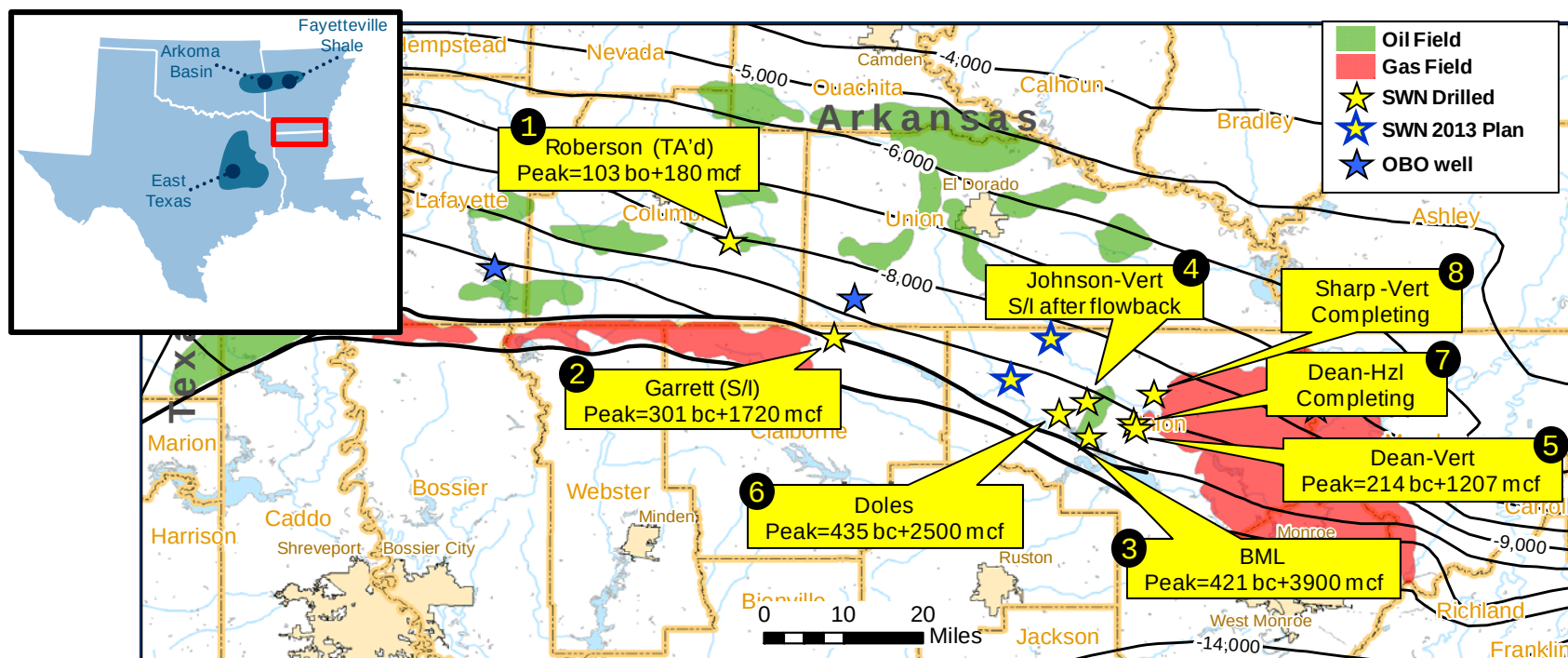


Total
Well
Count

92 | 67 | 45 | 30 | 24 | 20 | 17 | 13 | 7 | 1 | 1

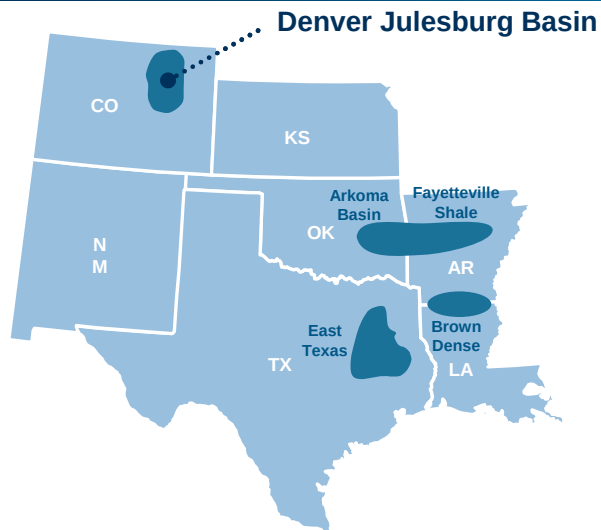
Notes: Data as of March 31, 2013.

Brown Dense Exploration Project



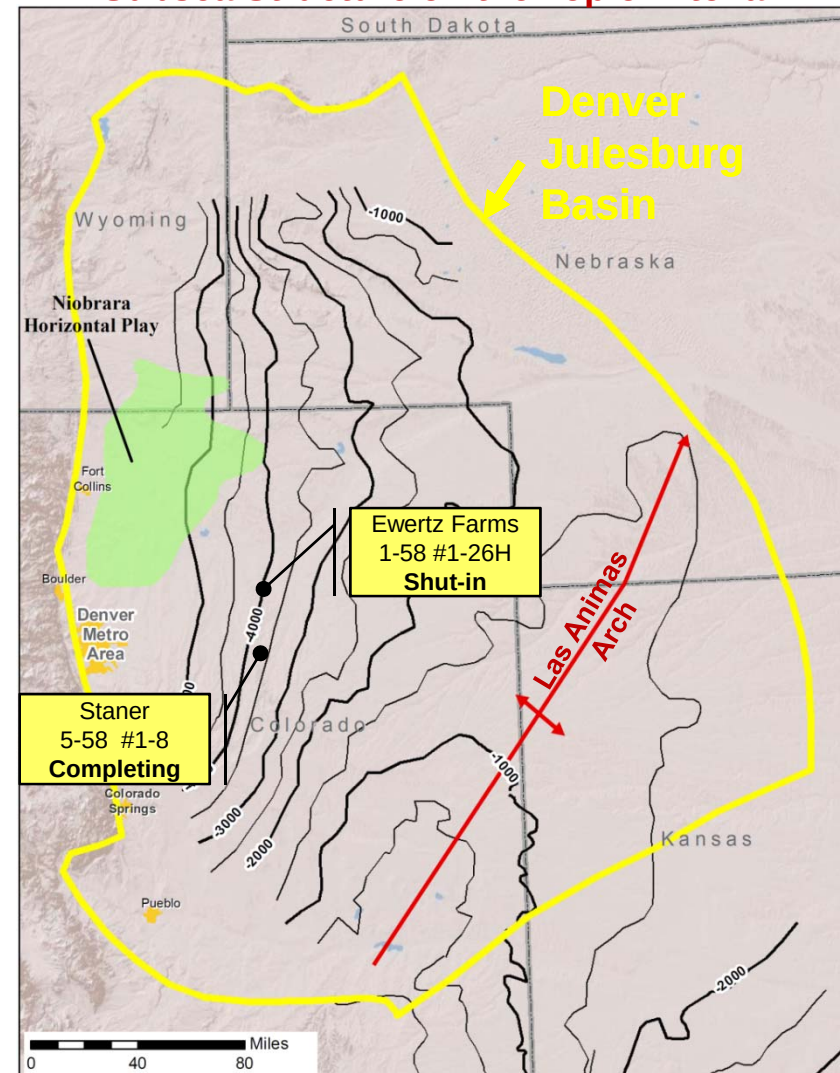
- SWN currently holds 507,000 net acres in Lower Smackover Brown Dense play. Total land cost of approx. \$419 per acre; 81% NRI; most leases have 4-year terms and 4-year extensions.
- Targeting oil and wet gas window in Upper Jurassic age, kerogen-rich carbonate in southern Arkansas and northern Louisiana.
 - Targeting 300 to 550 feet thick section at depths of 8,000 - 11,000 feet.
- Three wells placed on production.
- Completing two wells in the second quarter of 2013.

Denver Julesburg Basin Exploration Project



- SWN holds 302,000 net acres at 12/31/12 with a total land cost of approx. \$172 per acre; 85% NRI; leases with 5-year terms and 3-year extensions
- Targeting unconventional oil in late Pennsylvanian-age carbonates and shales with thicknesses of 300 - 750 feet at depths of 8,000 - 10,500 feet
- Currently completing a lateral in the Staner 5-58 #1-8 in the Marmaton formation

Subsea Structure on the Top of Atoka



Outlook for 2013

- Production target of 631-642 Bcfe in 2013 (estimated growth of ~13%).

	2012 Actual	2013 Guidance NYMEX Price Assumption		
	\$2.79 Gas \$94.94 Oil	\$3.50 Gas \$85.00 Oil	\$3.75 Gas \$85.00 Oil	\$4.00 Gas \$85.00 Oil
➤ Adj. Net Income	\$485.2 MM ⁽¹⁾	\$580-\$590 MM	\$620-\$630 MM	\$665-\$675 MM
➤ Adj. Diluted EPS	\$1.39 ⁽¹⁾	\$1.66-\$1.69	\$1.77-\$1.80	\$1.90-\$1.93
➤ EBITDA ⁽²⁾	\$1,636.1 MM	\$1,860-\$1,870 MM	\$1,930-\$1,940 MM	\$2,005-\$2,015 MM
➤ Net Cash Flow ⁽²⁾	\$1,598.9 MM	\$1,800-\$1,810 MM	\$1,870-\$1,880 MM	\$1,940-\$1,950 MM
➤ CapEx	\$2,080.5 MM	\$1,985 MM ⁽³⁾	\$1,985 MM ⁽³⁾	\$1,985 MM ⁽³⁾
➤ Debt %	35% ⁽⁴⁾	33%-35%	32%-34%	31%-33%

(1) Adjusted net income and adjusted diluted EPS excludes non-cash ceiling test impairments and unrealized gains and losses on derivative contracts. Both are non-GAAP financial measures.

(2) Net cash flow is net cash flow before changes in operating assets and liabilities. Net cash flow and EBITDA are non-GAAP financial measures.

(3) Excludes the pending acquisition of properties in the Marcellus Shale announced in April 2013.

(4) 2012 book capitalization includes the effect of \$1,192.4 million (after-tax) in non-cash ceiling test impairments recorded in 2012.

- Invest in the Highest PVI Projects.
- Flexibility in 2013 Capital Program.
- Maintain Strong Balance Sheet.
- Deliver the Numbers.
 - Production and Reserves.
 - Maximize Cash Flow.
- Curiosity to Learning to Innovation to V^+ .

Appendix

Financial & Operational Summary



	Quarter Ended March 31,		Year Ended December 31,		
	2013	2012	2012	2011	2010
	(\$ in millions, except per share amounts)		(\$ in millions, except per share amounts)		
Revenues	\$733.6	\$654.8	\$2,715.0	\$2,952.9	\$2,610.7
EBITDA ⁽¹⁾	431.9 ⁽²⁾	379.4	1,636.1	1,779.6	1,612.3
Adjusted Net Income ⁽³⁾	146.0	106.4	485.2	637.8	604.1
Net Cash Flow ⁽¹⁾	426.3	370.8	1,598.9	1,766.0	1,579.7
Adjusted Diluted EPS ⁽³⁾	\$0.42	\$0.30	\$1.39	\$1.82	\$1.73
Diluted CFPS ⁽¹⁾	\$1.22	\$1.06	\$4.59	\$5.05	\$4.52
Production (Bcfe)	147.8	133.4	565.0	500.0	404.7
Realized Avg. Gas Price (\$/Mcf)	\$3.43	\$3.48	\$3.44	\$4.19	\$4.64
Realized Avg. Oil Price (\$/Bbl)	\$106.93	\$104.39	\$101.54	\$94.08	\$76.84
Realized Avg. NGL Price (\$/Bbl)	\$47.97	---	---	---	---
Finding Cost (\$/Mcfe) ⁽⁴⁾			\$2.08	\$1.31	\$1.02
Reserve Replacement (%) ⁽⁴⁾			163%	299%	430%
Net Debt/Proved Reserves (\$/Mcfe)			\$0.42	\$0.23	\$0.22
Net Debt/Avg. Daily Production (\$/Mcfe)	\$1,023	\$999	\$1,082	\$969	\$972
Net Debt/Total Capitalization	35%	25%	35%	25%	27%

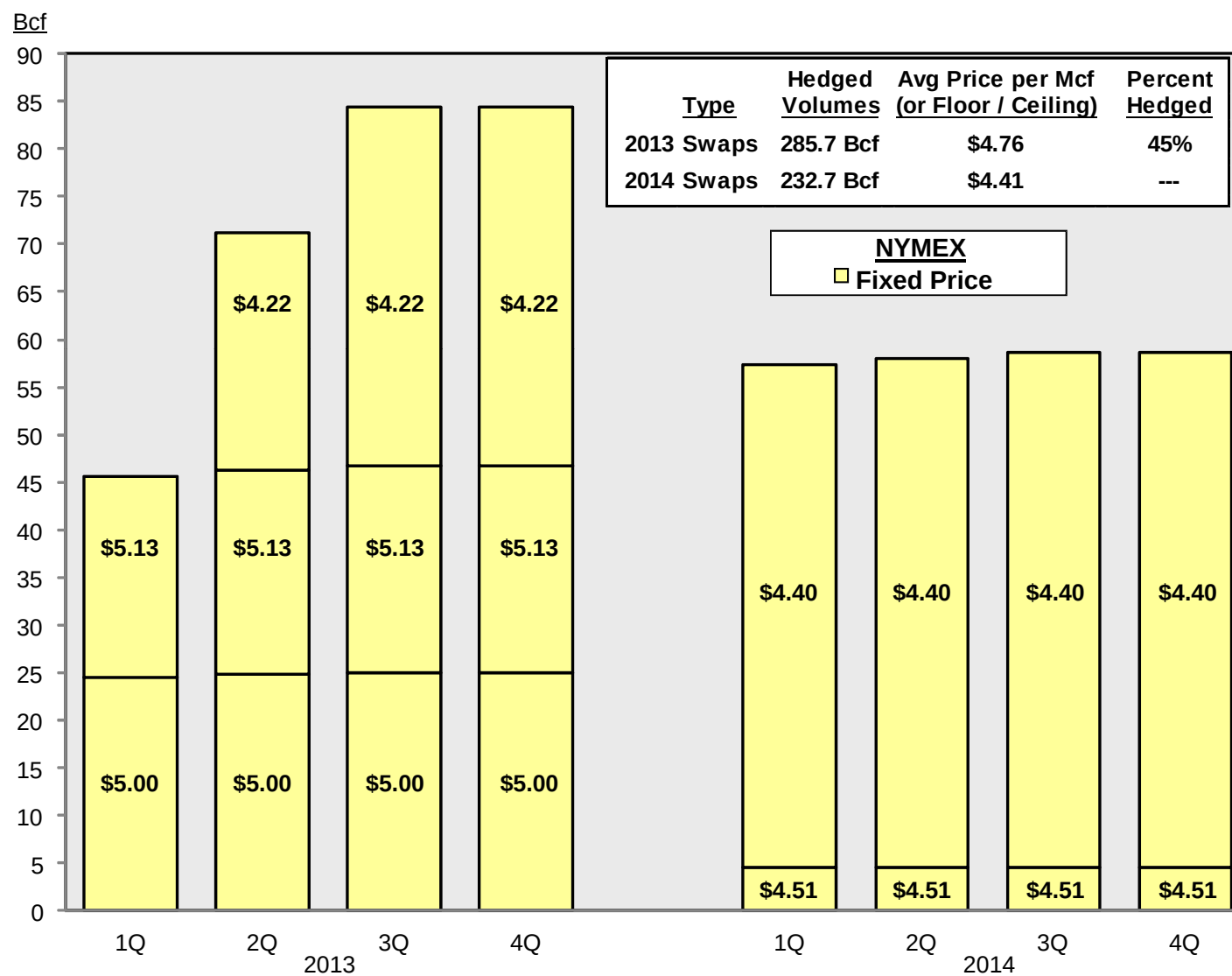
(1) Net cash flow is net cash flow before changes in operating assets and liabilities. Net cash flow, EBITDA and diluted CFPS are non-GAAP financial measures.

(2) EBITDA for Q1 2013 excludes \$30.8 million (pre-tax) of unrealized net loss on derivative contracts. EBITDA is a non-GAAP financial measure.

(3) Adjusted net income and adjusted diluted EPS excludes non-cash ceiling test impairments and unrealized gains and losses on derivative contracts. Both are non-GAAP financial measures.

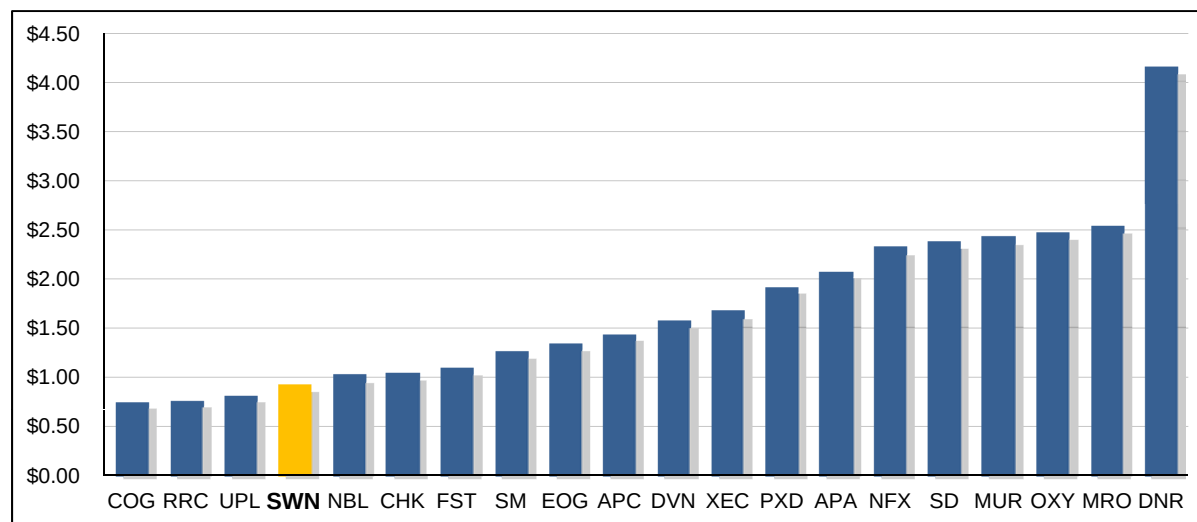
(4) Excludes reserve revisions and excludes capital investments in our sand facility, drilling rig related and ancillary equipment.

Gas Hedges in Place Through 2014

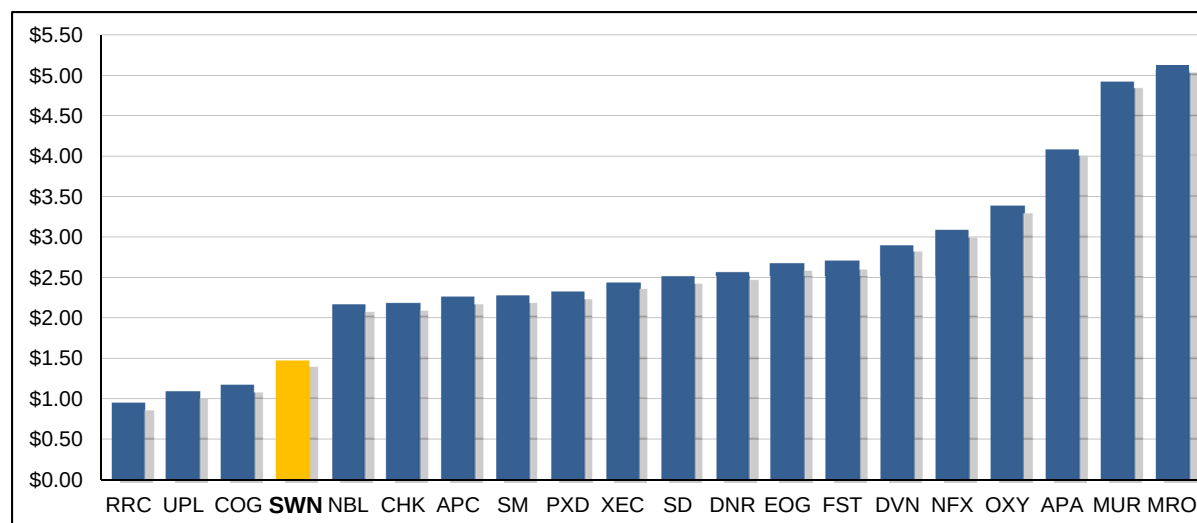


SWN is One of the Lowest Cost Operators

Lifting Cost per Mcfe of Production (3 year average)



Finding & Development Cost per Mcfe (3 year average)



Source: Public filings

Note: All data as of December 31, 2010, 2011 and 2012. APC - Anadarko Petroleum, APA - Apache, COG - Cabot Oil & Gas, CHK - Chesapeake Energy, XEC - Cimarex Energy, DNR - Denbury Resources, DVN - Devon Energy, EOG - EOG Resources, FST - Forest Oil, MRO - Marathon Oil, MUR - Murphy Oil, NFX - Newfield Exploration, NBL - Noble Energy, OXY - Occidental Petroleum, PXD - Pioneer Natural Resources, RRC - Range Resources, SD - Sandridge Energy, SM - SM Energy, SWN - Southwestern Energy, UPL - Ultra Petroleum.
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, and purchases (excludes reserve revisions).

$\frac{R^2}{A} \rightarrow V^+$

Marcellus Shale - Horizontal Well Performance

	30th-Day Avg. Rate (# of Wells)	60th-Day Avg. Rate (# of Wells)	120th-Day Avg. Rate (# of Wells)	Average of CLAT (ft)
Q3 2010	1,405 (1)	3,680 (1)	2,491 (1)	2,927
Q4 2010	5,584 (6)	5,602 (6)	5,446 (6)	3,805
Q1 2011	5,052 (3)	6,013 (3)	5,525 (3)	3,864
Q2 2011	6,114 (7)	6,835 (7)	8,231 (7)	4,780
Q4 2011	5,284 (5)	4,508 (5)	6,011 (5)	4,129
Q1 2012	7,327 (2)	8,247 (2)	7,966 (2)	4,009
Q2 2012	3,859 (17)	3,677 (17)	3,958 (17)	3,934
Q3 2012	4,493 (8)	4,654 (8)	4,682 (8)	4,380
Q4 2012	4,606 (22)	4,760 (22)	5,151 (12)	3,830
Q1 2013	4,923 (12)	5,438 (2)		3,976

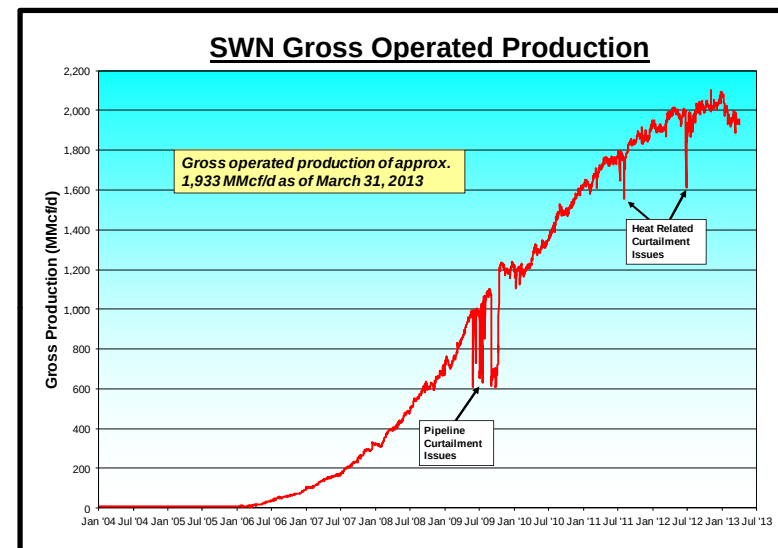
Notes: Data as of March 31, 2013.

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	2,666 (132)	2,372 (132)	4,847
4th Qtr 2011	142	3,646	2,606 (142)	2,243 (142)	4,703
1st Qtr 2012	146	3,319	2,421 (146)	2,131 (146)	4,743
2nd Qtr 2012	131	3,500	2,515 (131)	2,225 (131)	4,840
3rd Qtr 2012	105	3,857	2,816 (105)	2,447 (105)	4,974
4th Qtr 2012	111	3,962	2,815 (111)	2,405 (111)	4,784
1st Qtr 2013	102	3,301	2,373 (76)	2,133 (45)	4,942

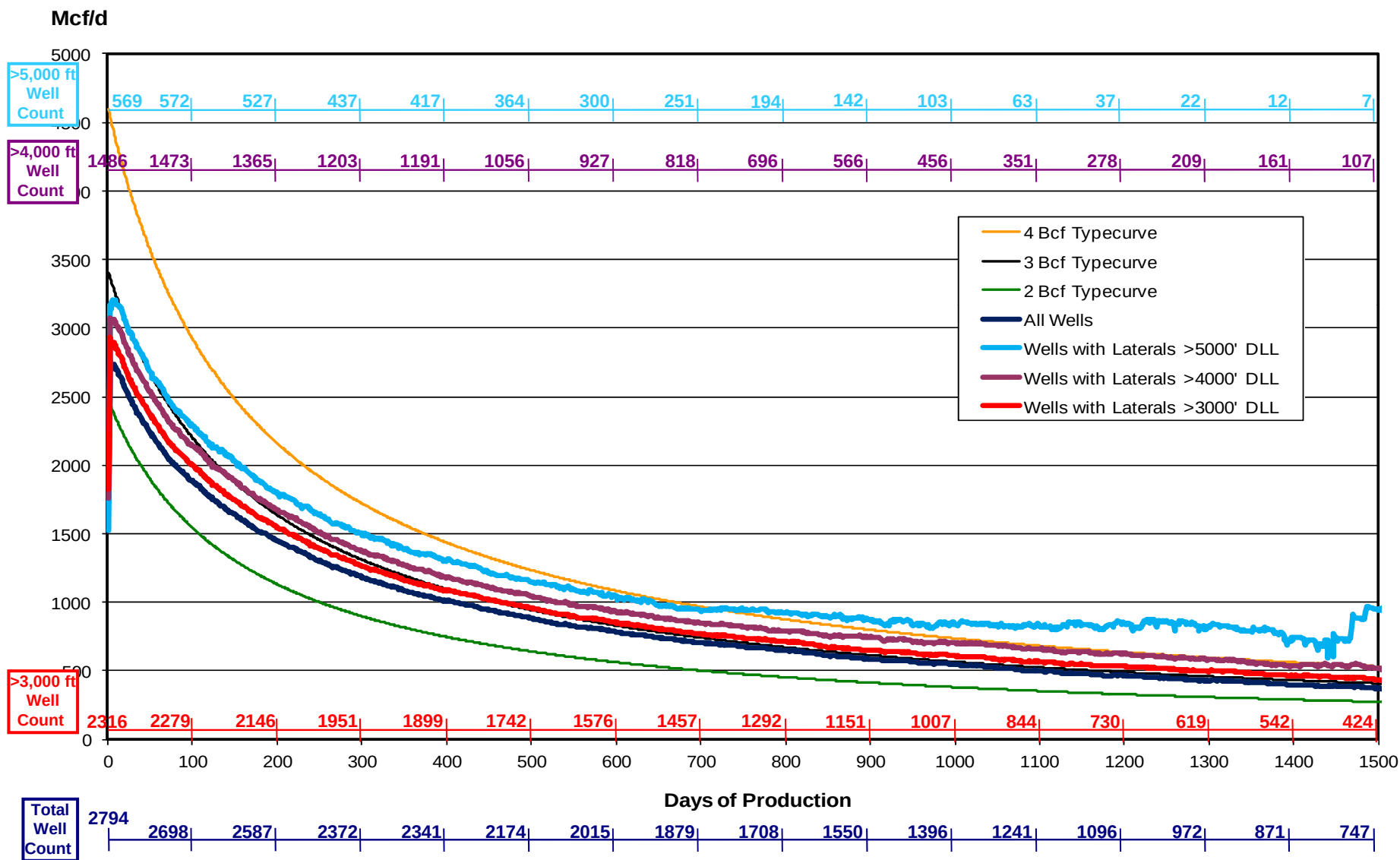
Note: Data as of March 31, 2013.

- (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.



- Gross operated production of approx. 1,933 MMcf/d as of March 31, 2013
- 2012 Fayetteville Shale F&D cost of \$2.53/Mcf

Fayetteville Shale - Horizontal Well Performance



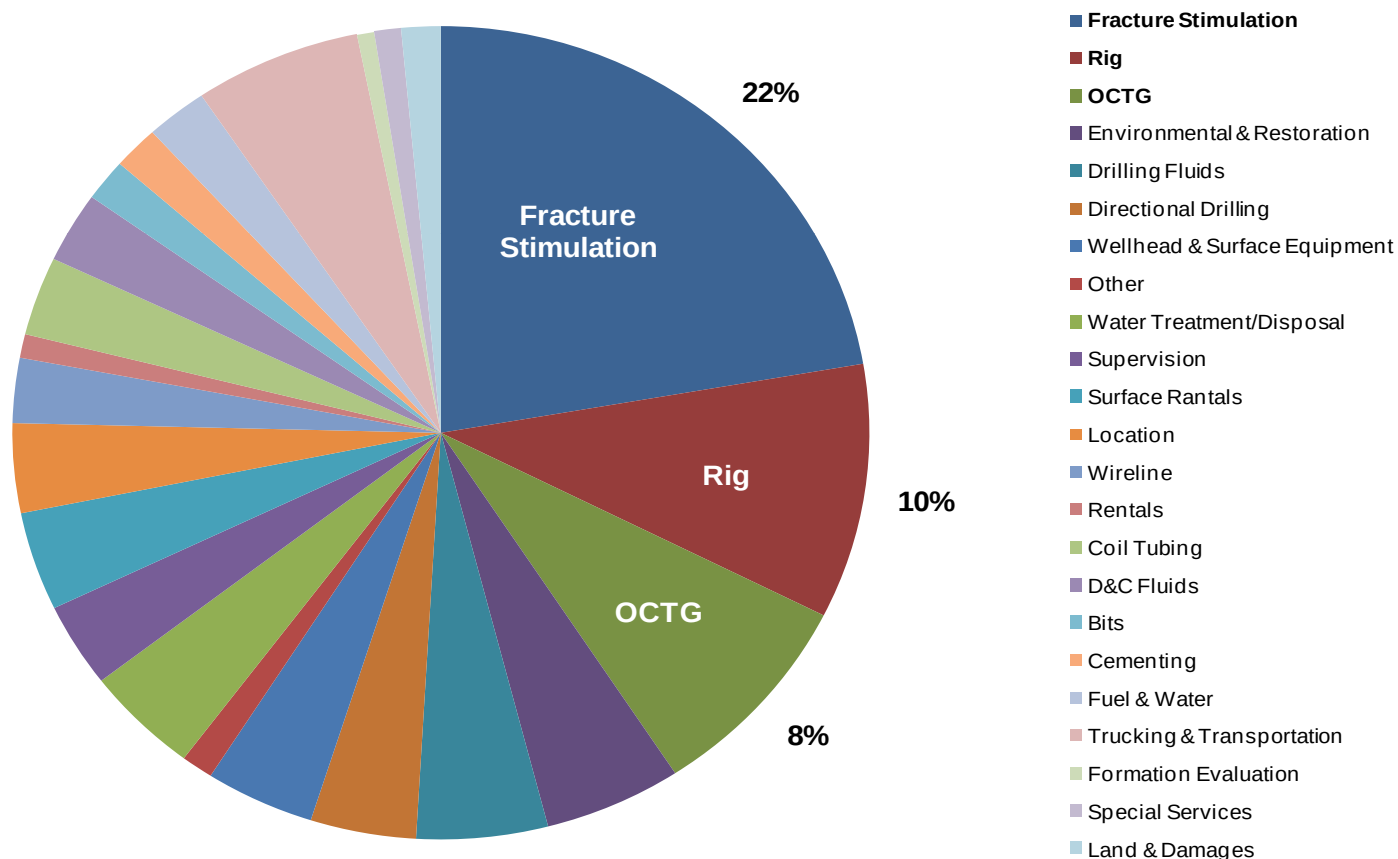
Notes: Data as of March 31, 2013. Excludes wells with mechanical problems (31).

$\frac{R^2}{A} \rightarrow V^+$

Drilling & Completion Major Cost Categories

Average 2013 Fayetteville Shale Well Cost Estimate

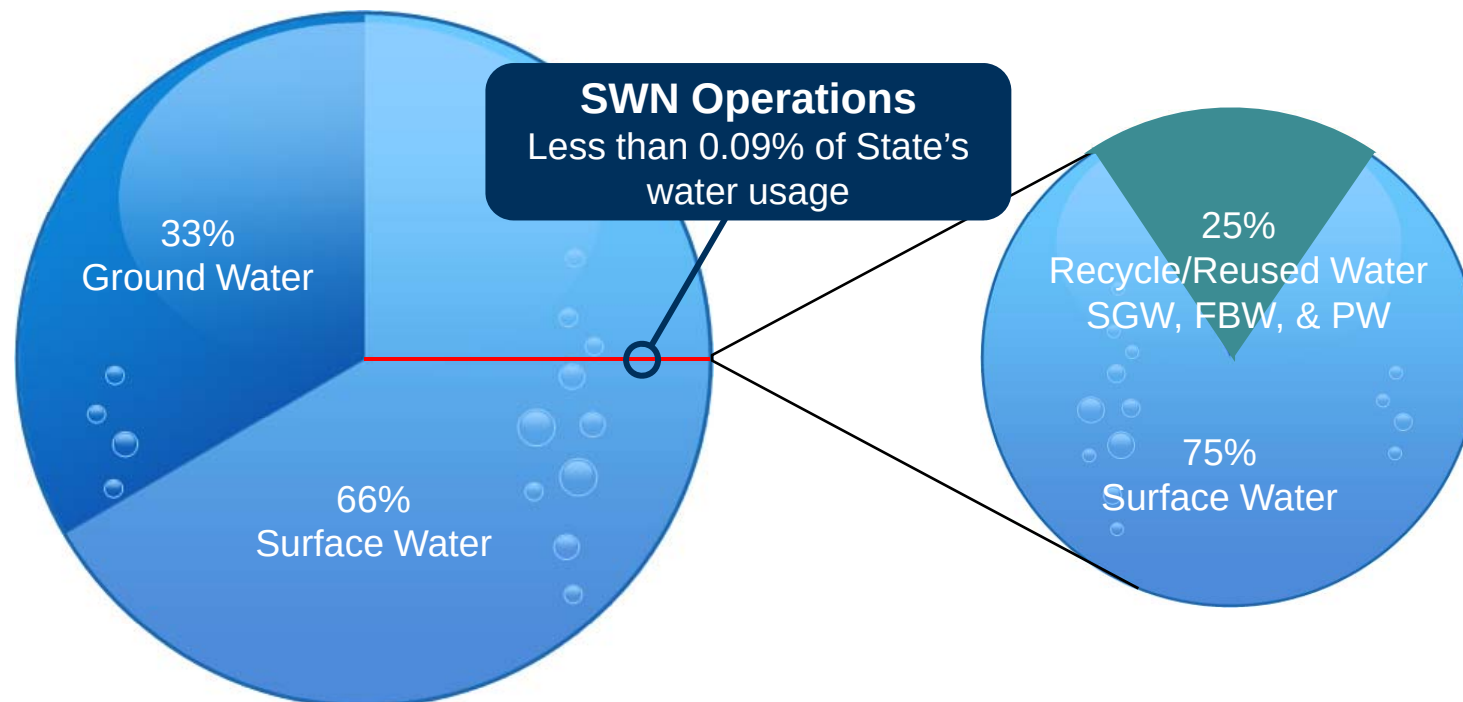
Major Cost Categories - \$2,725M



Water Demand: Perspective

Statewide Demand:
11,500 million gallons/day

SWN Operations Demand:
10 million gallons/day (600 Wells/year)



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.

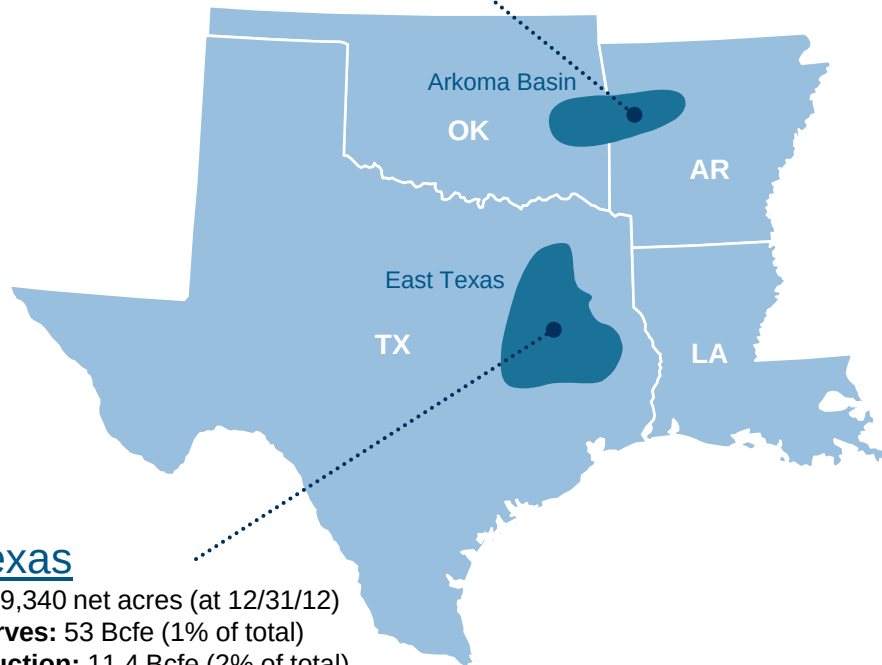
ArkLaTex Division

Arkoma Basin

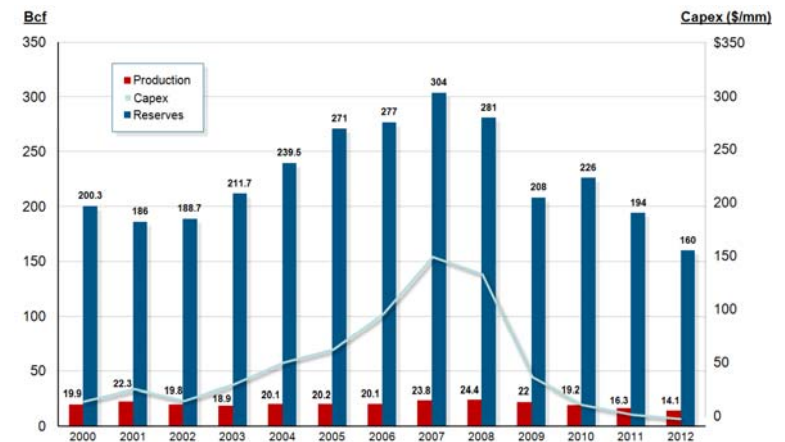
Acreage: 114,287 net acres (at 12/31/12)

2012 Reserves: 160 Bcf (4% of total)

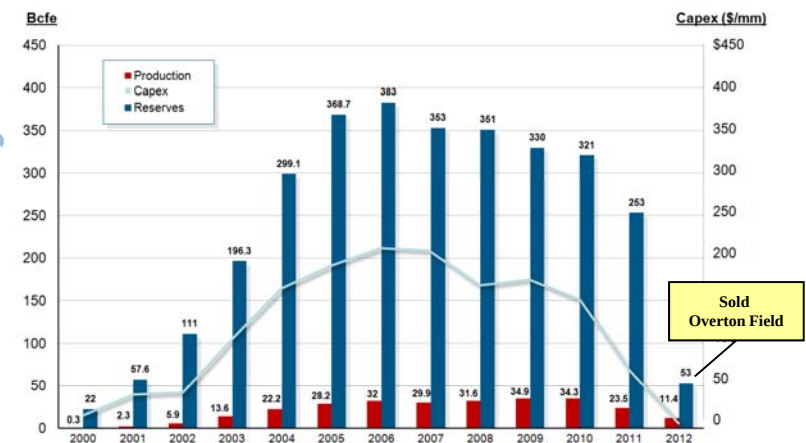
2012 Production: 14.1 Bcf (2% of total)



Arkoma Basin

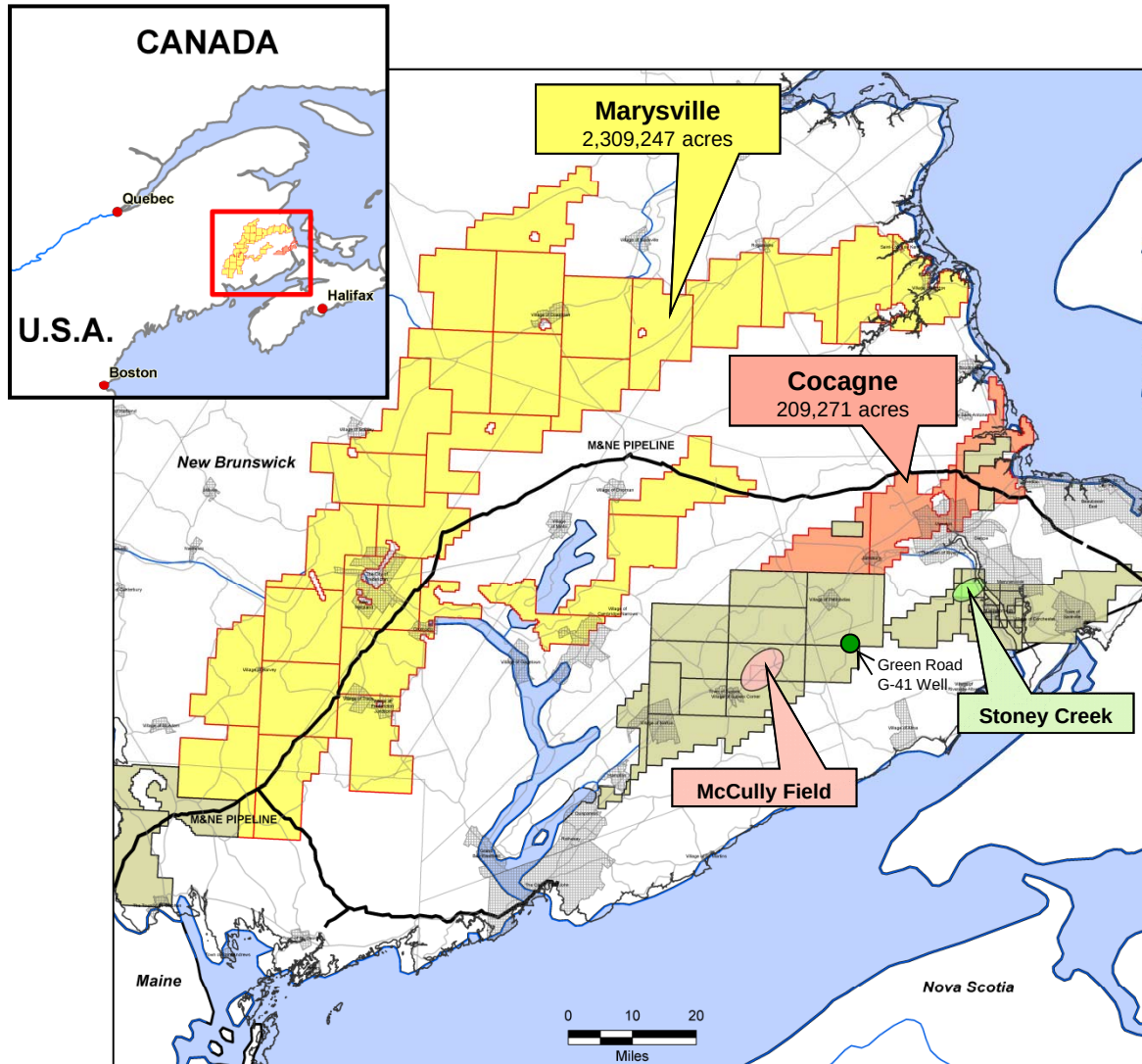


East Texas



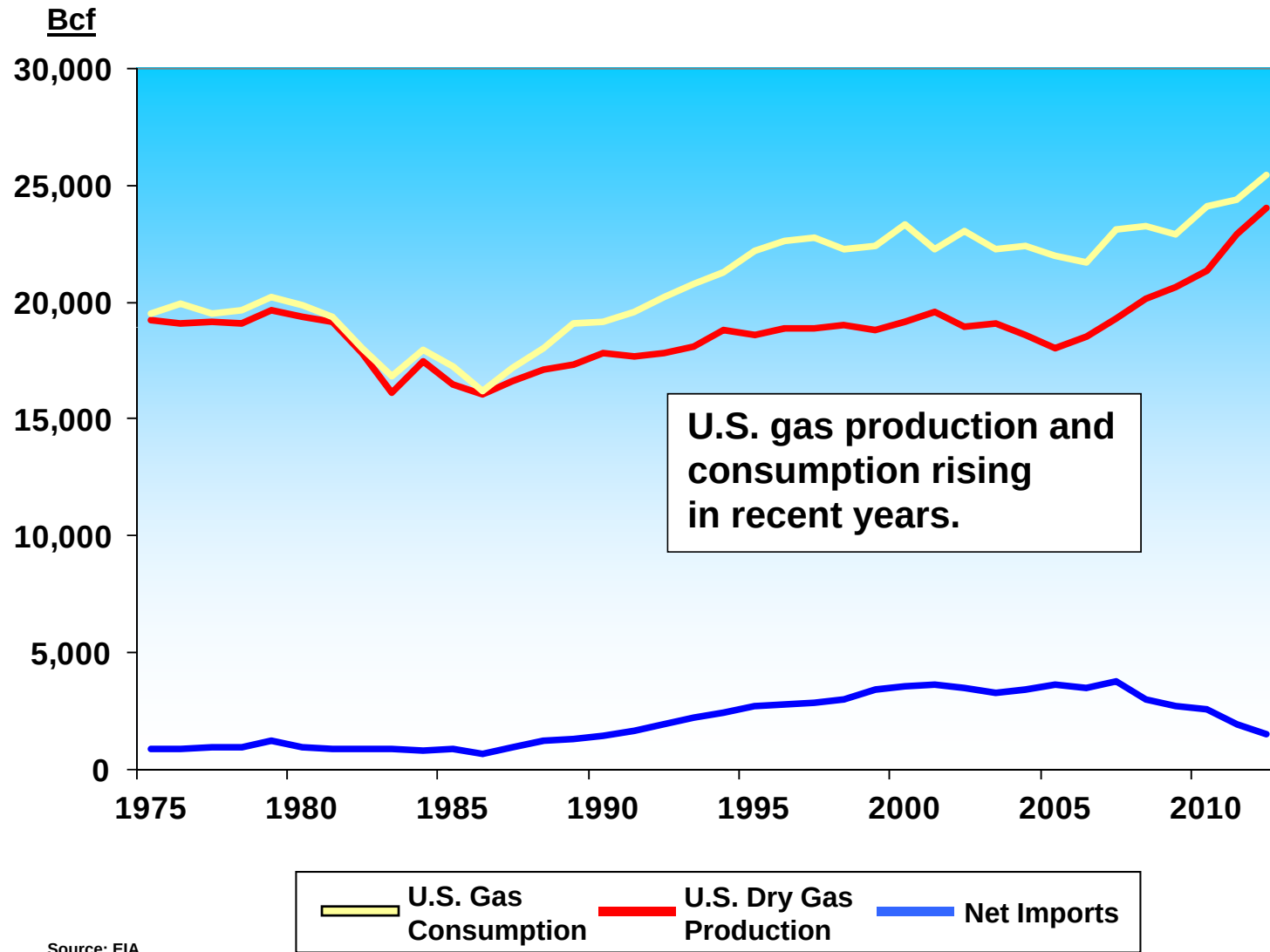
Notes: Conventional Arkoma acreage excludes 124,653 net acres in the conventional Arkoma Basin operating area that are also within the company's Fayetteville Shale focus area.

New Brunswick, Canada Exploration Project

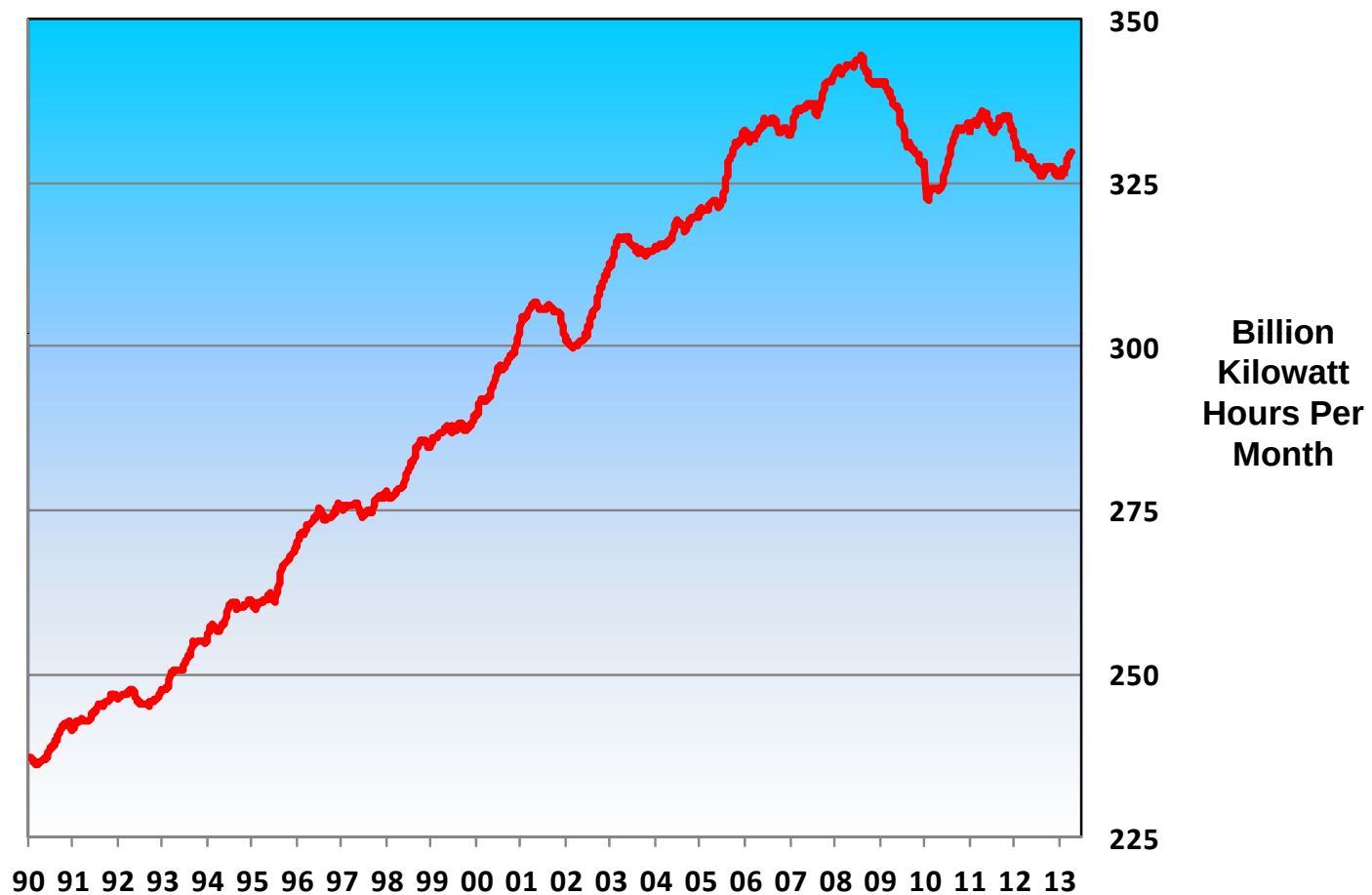


- SWN currently holds exploration licenses to over 2.5 million acres within the Maritimes Basin
- Principal targets are the conventional and unconventional sandstone and shale reservoirs of the Horton Group (Frederick Brook Shale)
- Oil and gas production from fields along southern flank:
 - McCully – reserves 190 bcfg
 - Stoney Creek – cum 800,000 bo, 30 bcfg
- 3-year initial exploration license to complete work program
 - Total \$47MM work commitment with options of multiple 5-yr extension leases

U.S. Gas Consumption and Sources



U.S. Electricity Consumption

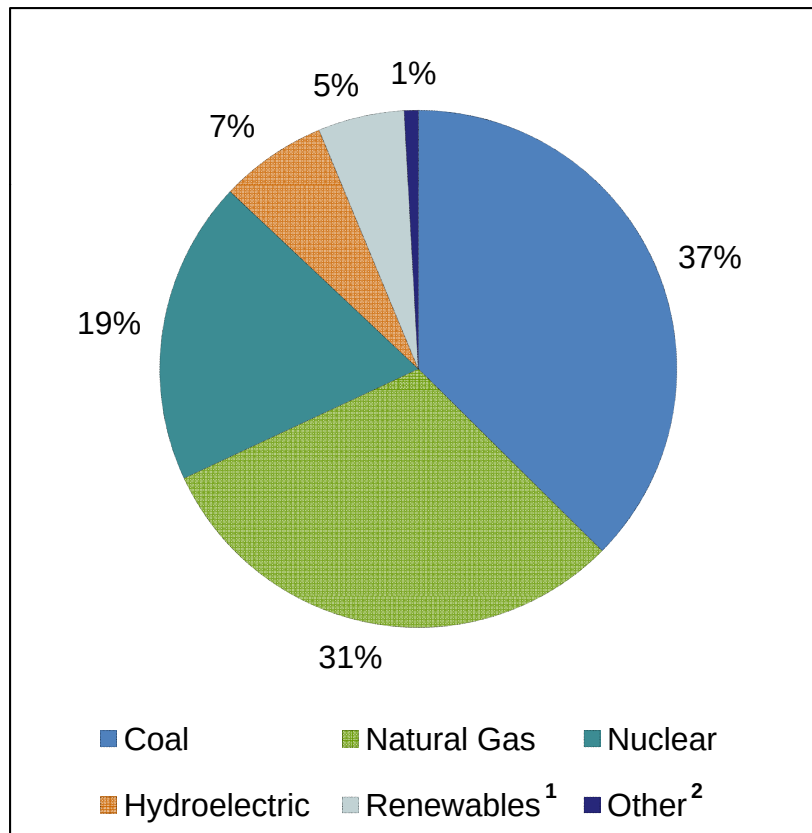


Source: Edison Electric Institute

U.S. Electricity Generation

Electricity Generation by Energy Source

Total 4,060 Billion KWh in 2012.

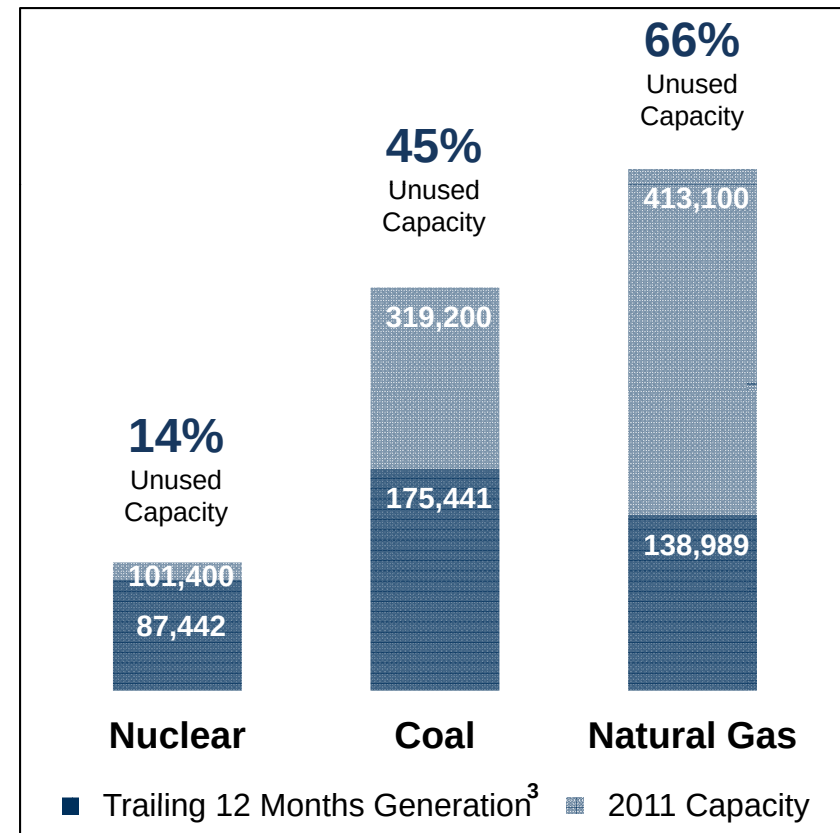


1. Geothermal, solar, wood, waste and wind
2. Petroleum and others gases
3. March 2012 – February 2013

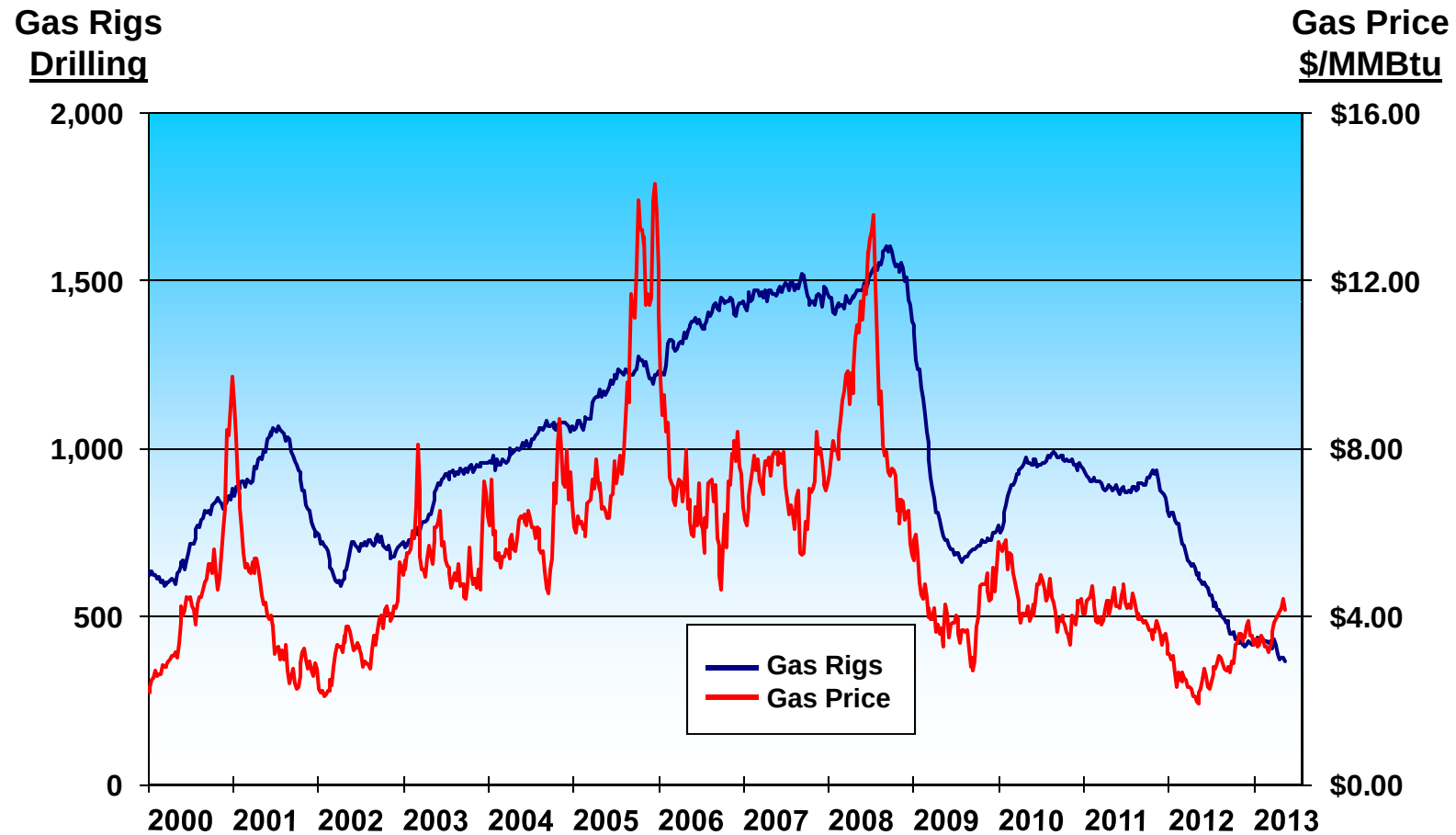
Source: EIA

Electricity Generation Capacities

While coal and nuclear power plants operate at high capacity, natural gas power plants are running at 34% of their capacity.

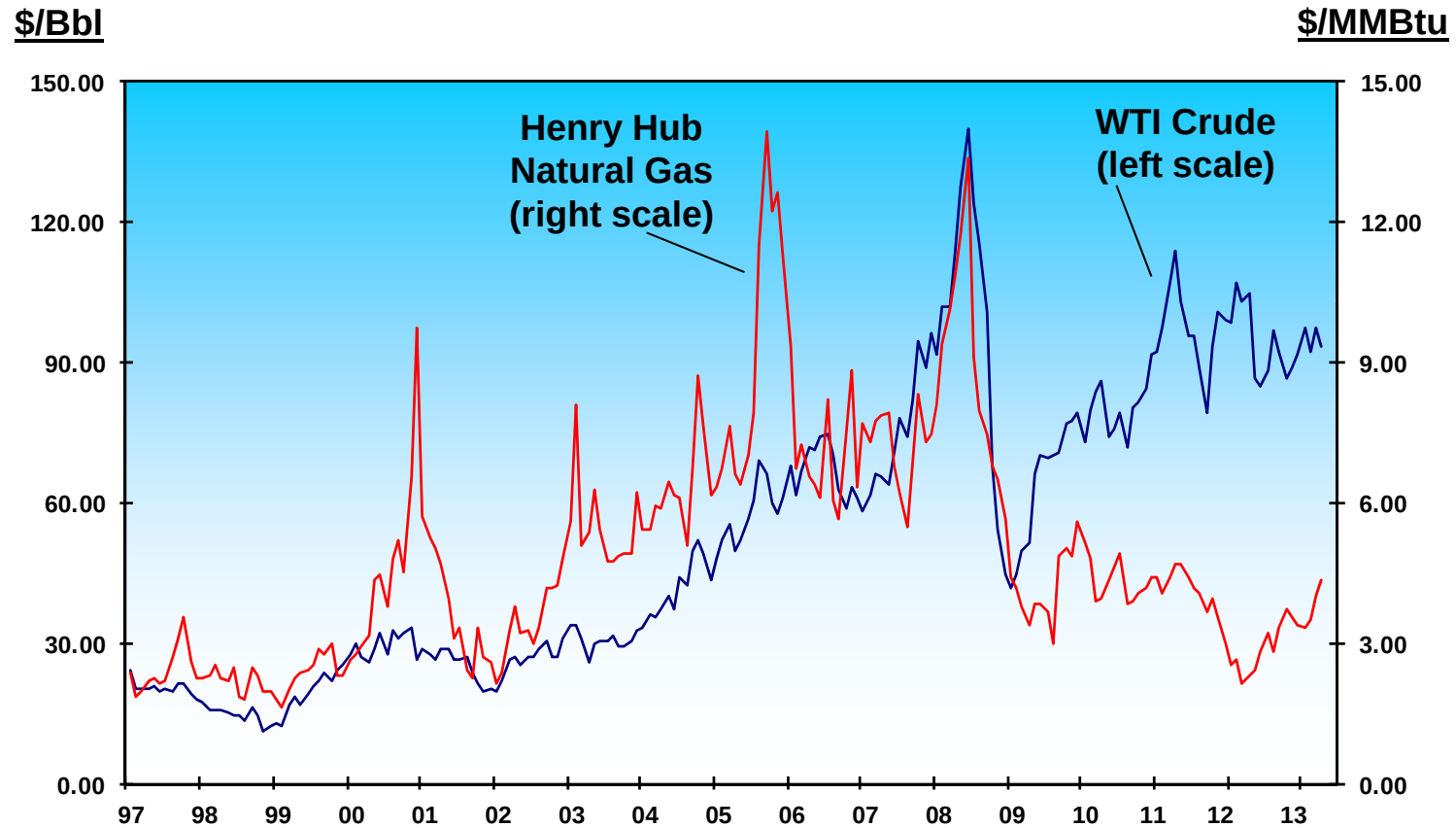


U.S. Gas Drilling and Prices



Source: Baker Hughes, Bloomberg

Oil and Gas Price Comparison



Source: Bloomberg

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.

	3 Months Ended March 31,		12 Months Ended December 31,		
	2013	2012	2012	2011	2010
			(in thousands)		
Net cash provided by operating activities	\$ 372,138	\$ 444,663	\$ 1,653,942	\$ 1,739,817	\$ 1,642,585
Add back (deduct):					
Change in operating assets and liabilities	54,114	(73,843)	(55,061)	26,201	(62,906)
Net cash flow	<u>\$ 426,252</u>	<u>\$ 370,820</u>	<u>\$ 1,598,881</u>	<u>\$ 1,766,018</u>	<u>\$ 1,579,679</u>

	2013 Guidance		
	NYMEX Commodity Price Assumption		
	\$3.50 Gas \$85.00 Oil	\$3.75 Gas \$85.00 Oil	\$4.00 Gas \$85.00 Oil
		(\$ in millions)	
Net cash provided by operating activities	\$1,800-\$1,810	\$1,870-\$1,880	\$1,940-\$1,950
Add back (deduct):			
Assumed change in operating assets and liabilities	--	--	--
Net cash flow	<u>\$1,800-\$1,810</u>	<u>\$1,870-\$1,880</u>	<u>\$1,940-\$1,950</u>

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.

	3 Months Ended March 31, 2013		3 Months Ended March 31, 2012		12 Months Ended December 31, 2012		12 Months Ended December 31, 2009	
	(\$ in thousands)	(per share)	(\$ in thousands)	(per share)	(\$ in thousands)	(per share)	(\$ in thousands)	(per share)
Net income (loss) attributable to SWN	\$ 127,515	\$ 0.36	\$ 107,704	\$ 0.31	\$ (707,064)	\$ (2.03)	\$ (35,650)	\$ (0.10)
Add back (deduct):								
Impairment of natural gas & oil properties (net of taxes)	-	-	-	-	1,192,412	3.42	558,305	1.62
Unrealized loss (gain) on derivative contracts (net of taxes)	18,473	0.06	(1,276)	(0.01)	(167)	---	---	---
Adjusted net income	<u>\$ 145,988</u>	<u>\$ 0.42</u>	<u>\$ 106,428</u>	<u>\$ 0.30</u>	<u>\$ 485,181</u>	<u>\$ 1.39</u>	<u>\$ 522,655</u>	<u>\$ 1.52</u>

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.

	3 Months Ended March 31,		12 Months Ended December 31,										
	2013	2012	2012	2011	2010	2009	2008	2007	2006	2005	2004	2003	2002
								(\$ in thousands)					
Net income (loss)	\$ 127,515	\$ 107,704	\$ (707,064) (1)	\$ 637,769	\$ 604,118	\$ (35,650) (4)	\$ 567,946	\$ 221,174	\$ 162,636	\$ 147,760	\$ 103,576	\$ 48,897	\$ 14,311
Add back:													
Net interest expense	9,021	7,338	35,657	24,075	26,163	18,638	28,904	23,873	679	15,040	16,992	17,311	21,466
Provision (benefit) for income taxes	85,097	70,718	(443,139) (2)	413,221	391,659	(16,363) (5)	350,999	135,855	99,399	86,431	59,778	28,372 (7)	8,708
Depreciation, depletion and amortization	179,467	193,627	2,750,687 (3)	704,511	590,332	1,401,470 (6)	414,460	294,500	151,795	96,641	74,919	56,833	54,095
EBITDA	\$ 401,100	\$ 379,387	\$ 1,636,141	\$ 1,779,576	\$ 1,612,272	\$ 1,368,095	\$ 1,362,309	\$ 675,402	\$ 414,509	\$ 345,872	\$ 255,265	\$ 151,413	\$ 98,580

(1) Net income (loss) includes after tax full cost ceiling impairments of our natural gas and oil properties of \$1,192.4 million.

(2) Provision (benefit) for income taxes includes the (\$747.3) million income tax benefit related to the non-cash ceiling impairments of our natural gas and oil properties.

(3) Depreciation, depletion and amortization includes \$1,939.7 million for non-cash ceiling impairments of our natural gas and oil properties.

(4) 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.

(5) 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.

(6) Depreciation, depletion and amortization includes the \$907.8 million non-cash ceiling impairment of our natural gas and oil properties recorded in Q1 2009.

(7) Provision for income taxes for 2003 includes the tax benefit associated with the cumulative effect of adoption of accounting principle.

The table below reconciles forecasted EBITDA with forecasted net income for 2013, assuming various NYMEX price scenarios and the corresponding estimated impact on the company's results for 2013, including current hedges in place:

	2013 Guidance			
	Overall Corporate			
	NYMEX Commodity Price Assumption			Midstream Services Segment
	\$3.50 Gas \$85.00 Oil	\$3.75 Gas \$85.00 Oil	\$4.00 Gas \$85.00 Oil	(1)
	(\$ in millions)			
Net income attributable to SWN	\$580-\$590	\$620-\$630	\$665-\$675	\$170-\$175
Add back:				
Provision for income taxes	387-393	413-420	443-450	113-117
Interest expense	36-38	35-37	34-36	13-15
Depreciation, depletion and amortization	850-860	850-860	850-860	55-57
EBITDA	\$1,860-\$1,870	\$1,930-\$1,940	\$2,005-\$2,015	\$355-\$360

(1) Midstream Services segment results assume NYMEX commodity prices of \$3.50 per Mcf for natural gas and \$85.00 per barrel for crude oil for 2013.