

Slide Presentation dated June 7, 2004

The following slides were presented June 7, 2004 to investors and analysts at the RBC Capital Markets 2004 North American Energy and Power Conference held at the Westin Copley Place Hotel in Boston, Massachusetts.

(Slide 1)**Southwestern Energy Company**

Presentation to RBC Capital Markets 2004 North American Energy and Power Conference

June 2004

NYSE: SWN

This slide contains a picture of a snow-capped volcano. The caption above reads "The Power Within." The Company's formula $\frac{R^2}{A} \rightarrow V^+$ is located in the bottom right corner.

(Slide 2)**Southwestern Energy Company (NYSE: SWN)****General Information**

Southwestern Energy Company is an independent energy company primarily focused on the exploration for and production of natural gas. Our strategy is to add at least \$1.30 in discounted value for every dollar invested in a focused exploration and production program in the Arkoma and Permian Basins, East Texas and the onshore Gulf Coast.

Market Data as of June 1, 2004

Shares of Common Stock Outstanding	36,077,888
Market Capitalization	\$922,000,000
Institutional Ownership	91.6%
Management Ownership	7.0%
52-Week Price Range	\$14.41 (07/24/2003) \$26.60 (04/27/2004)

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(Slide 3)
Forward-Looking Statements

This presentation includes certain statements that 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, other than historical financial information, may be deemed to be forward-looking statements. Although the Company believes the expectations expressed in such forward-looking statements are based on reasonable assumptions, investors are cautioned that any such statements are not guarantees of future performance and that actual results or developments may differ materially from those projected in the forward-looking statements. Important factors that could cause actual results to differ materially from those in the forward-looking statements herein include, but are not limited to, the timing and extent of changes in commodity prices for gas and oil, the timing and extent of the Company's success in discovering, developing, producing, and estimating reserves, property acquisition or divestiture activities that may occur, the effects of weather and regulation on the Company's gas distribution segment, increased competition, legal and economic factors, governmental regulation, the financial impact of accounting regulations and critical accounting policies, changing market conditions, the comparative cost of alternative fuels, conditions in capital markets and changes in interest rates, availability of oil field services, drilling rigs, and other equipment, as well as other factors beyond the Company's control. For additional information with respect to certain of these and other factors, see the reports filed by the Company with the Securities and Exchange Commission. 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. Without limiting the foregoing, all financial information and strategies contained herein have been prepared by the Company and are based on a number of assumptions that are subject to significant uncertainties and contingencies, many of which are beyond the Company's control. There can be no assurance that the assumptions will prove to be accurate or that the amounts included in the projections will be realized or transactions currently contemplated in strategies will be completed, and actual future results may be materially higher or lower than those shown.

(Slide 4)
About Southwestern

- Focused on domestic production of natural gas.
 - 503 Bcfe of reserves; 91% natural gas; 12.2 R/P at year-end 2003.
- Track record of adding significant reserves at low costs.
 - Since 1999, we've averaged production growth of 6% per year, 230% reserve replacement, F&D cost of \$1.10 per Mcfe.

- E&P strategy built on organic growth through the drillbit.
 - Approximately 80% of 2004 planned E&P capital allocated to drilling.
- Proven management team has increased Southwestern's market capitalization from \$187 million at year-end 1998 to approximately \$900 million today.

- Strategy built on the Formula: $\frac{R^+}{A} \rightarrow V^+$

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

(Slide 5)
2003 Highlights

- Follow-on equity offering completed in March 2003. Raised \$103 million to accelerate development drilling at Overton Field and reduce debt.
 - Improved our debt-to-capital ratio to 45% at 12/31/03 from 66% at 12/31/02.
- Record operating and financial results.
 - Record reserve additions of 144.5 Bcfe, replacing 351% of production.
 - Reserve growth of 21% to 503 Bcfe.
 - Record production of 41.2 Bcfe.
 - Received \$4.1 million annual rate increase for utility.
 - Record net income of \$48.9 million.
 - Record EBITDA⁽¹⁾ of \$152.3 million.
- New \$300 million revolving credit facility put in place January 2004.

(1) EBITDA is a non-GAAP financial measure. See explanation and reconciliation of non-GAAP financial measures on pages 30 and 31.

(Slide 6)
Proven Track Record

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

	1999	2000	2001	2002	2003
Production (Bcfe)	32.9	35.7	39.8	40.1	41.2
Reserve Replacement	150%	196%	224%	209%	351%
EBITDA (\$MM)⁽¹⁾	\$76.1	\$103.2	\$134.6	\$99.8	\$152.3
F&D Cost (\$/Mcfe)	\$1.20	\$0.99	\$1.11	\$1.02	\$1.18

Note: Reserve data excludes reserve revisions.

(1) EBITDA is a non-GAAP financial measure. See explanation and reconciliation of non-GAAP financial measures on pages 30 and 31.

(Slide 7)

E&P Focused

This slide contains a map of Arkansas, Louisiana, Oklahoma, Texas and New Mexico with shadings to denote the Arkoma and Permian Basins, the Gulf Coast region and the East Texas region. Lines trace gas distribution pipelines and the Ozark Pipeline.

E&P Segment

- 2003 Reserves: 503 Bcfe
- 91% Natural Gas
- 82% Proved Developed
- Reserve Life: 12.2 years
- 2003 Production: 41.2 Bcfe

Arkoma

- Reserves – 211.7 Bcf (42%)
- Production – 18.9 Bcf (46%)
- Maintain our strong position through low-risk development drilling and workovers.

East Texas (Overton)

- Reserves – 196.3 Bcfe (39%)
- Production – 13.6 Bcfe (33%)
- Grow through low-risk infill drilling.

Gulf Coast

- Reserves – 39.5 Bcfe (8%)
- Production – 4.5 Bcfe (11%)
- Reduce our high-risk exploration.

Permian

- Reserves – 55.6 Bcfe (11%)
- Production – 4.2 Bcfe (10%)
- Focus on medium-risk exploration.

Utility Segment

- 142,000 customers in N. Arkansas
- 6th fastest growing region in U.S.
- Received \$4.1 MM annual rate increase Oct. 2003

(Slide 8)
Capital Investments

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

	2001	2002	2003	2004 Plan
	(\$ in millions)			
Utility & Corporate	\$7.1	\$6.9	\$9.3	\$9.5
Property Acquisitions	\$0.7	\$0.1	-	-
Cap. Exp. & Other	\$9.9	\$10.9	\$12.4	\$19.3
Leasehold & Seismic	\$9.8	\$9.2	\$19.0	\$18.0
Development Drilling	\$44.2	\$46.3	\$119.7	\$162.3
Exploration Drilling	\$20.8	\$18.7	\$19.8	\$29.9
Total	\$92.5 ⁽¹⁾	\$92.1	\$180.2	\$239.0

This slide also contains a pie chart of Company capital investments by area of operation, summarized as follows:

	% of Total Capital Investments
East Texas	54%
Arkoma	21%
Gulf Coast	6%
Permian	5%
Other E&P	10%
Utility	4%

- E&P capital program heavily weighted to low-risk drilling in 2004:
 - Low-risk East Texas (\$124.4 MM, 54%) and Arkoma (\$51.2 MM, 21%)
 - Medium-risk Permian Basin (\$11.8 MM, 5%) and
 - Higher-risk, but larger potential Gulf Coast (\$13.5 MM, 6%).
- Invested \$11.0 MM in 2003 to acquire 345,300 acres in “New Venture” areas.
 - Acquired additional 95,000 acre CBM project in Montana in early 2004.
 - Plan to invest additional \$23.7 MM in 2004.
- 84% of E&P capital allocated to drilling in 2004.

(1) Net of \$13.5 million reimbursement from Overton Field partnership.

Note that the information contained on this slide constitutes a "forward-looking statement".

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East Texas – Overton Field

This slide contains a map of Smith County, Texas where the Overton Field is located. Existing wells at year-end 2002, 2003 development wells, and future development locations are denoted. It is stated that the Overton Field contains 17,900 acres and the South Overton Farm-in Acreage contains 6,500 acres.

- Purchased original 10,800 acres and 16 producing wells for \$6.1 million in 2000 (developed at 640-acre spacing).
- Drilled 90 wells in 2001-2003 with 100% success.
- Plan to drill 74 wells in 2004, a portion of which will be at 40-acre spacing.
- A large portion of the field will likely require 40-acre spaced wells to adequately develop the field.

Overton Field reserve potential:

	Well Count	Approx. Spacing (Acres)	Reserve Potential (Net Bcfe)
Original Wells	16	640	22
2001 - 2002 Development	33	365	89
2003 Development	57	170	102
Planned 2004 Development	74	100	105
Potential Future Development	76	<80	97
	256	<80	415

Overton Field Three-Year Average Results:

Reserve Replacement:	902%
LOE Cost (incl. Taxes) (\$/Mcf):	\$0.46
F&D Cost (\$/Mcf):	\$0.82

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(Slide 10)

Overton Field Gross Production

The graph contained in this slide displays the Overton Field gross production rate (MMcfe/d) from the year 2000 to the current period in 2004 and the potential gross production rate for 2004 under both an accelerated drilling program and under an eighteen well per year program.

Overton Field Net Production:

	Bcfe
2000	0.3
2001	2.3
2002	5.9
2003	13.6
2004 Forecast	19 – 21

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(Slide 11)

Overton Field – Improved Drilling Results

This slide portrays the improved drilling rate in the Overton Field since its purchase from Fina in 2001. Fina's average drilling rate was 55 days. Upon the Field's purchase in 2001 we decreased that rate to 35 days. It was further decreased to 27 days in 2002 and 23 days in 2003.

- Reduced drilling time by >50%.
- Increased initial production by 200%.
- Increased gross reserves by 60% (avg. EUR of 2.2 Bcfe per well in 2003).

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(Slide 12)

Arkoma Basin

This slide contains a map of Arkansas and Oklahoma with shading to denote the Arkoma Basin. The Ranger Anticline, Haileyville and the area known as the Fairway are further noted.

- “Legacy asset” that provides SWN with a stable production/reserve base and low-risk drilling opportunities with some upside exploration potential.
- Competitive advantages:
 - 60+ years of experience in the basin.
 - Large acreage position of 367,000 gross acres and 256,000 net acres.
- 2004 capital program includes drilling over 80 wells and 95 workovers.

Arkoma Basin Three-Year Average Results:

Reserve replacement:	116%
LOE cost (incl. Taxes) (\$/Mcf):	\$0.38

F&D cost (\$/Mcf):	\$1.14
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Ranger Anticline:

Success:	28/34 wells
Net EUR:	33.1 Bcf
F&D/Mcf:	\$.85

Haileyville:

Success:	23/31 wells
Net EUR:	11.4 Bcf
F&D/Mcf:	\$.75

Note that the information contained on this slide constitutes a "forward-looking statement".

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Ranger Anticline

This slide contains a map of the Ranger Anticline prospect with the Company's exploratory acreage and acreage held by production designated with shading. Also shown are SWN's successful wells at 12/31/03, 2004 proposed wells, the Smith #1-10, the Dulyea #1-10 and the Doggle #2-15 wells waiting on pipeline, the Albright #1-7 producing well and the Moua #1-10 plugged and abandoned.

Ranger Anticline:

Success:	28/34 wells
Net EUR:	33.1 Bcf
F&D/Mcf:	\$.85

- In early 2003 received approval to downspace field to 80 acres per well.
- Large acreage position of 4,400 gross developed acres and 37,100 gross exploratory acres.
- Average working interest 50% - 100%.
- SWN plans to drill up to 20 wells in area in 2004.
- Area has significant upside potential.

Ranger Anticline Potential on Held by Production Acreage:

	Well Count	Approx. Spacing (Acres)	Reserve Potential (Net Bcfe)
Producing Wells at 12/31/02	13	320	17
Successful Wells in 2003	9	180	12

2004 Development Wells	7	150	6
<u>Potential Future Locations</u>			
Prob/Poss Locations	24	80	19
TOTAL	53	80	54

Note that the information contained on this slide constitutes a “forward-looking statement”.

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Focused on Adding Value

<u>Typical First Year Economics:</u> ⁽¹⁾	<u>Overton Well</u> (per Mcfe)	<u>Ranger Well</u> (per Mcf)
Revenues	\$4.00	\$4.00
Production costs	<u>\$0.30</u>	<u>\$0.20</u>
Cash netback	\$3.70	\$3.80
F&D costs	\$0.85	\$0.80
Total Life Economics:		
Completed Well Cost ⁽²⁾	\$1.5 million	\$1.0 million
Pretax ROR ⁽³⁾	30%	35%
Pretax PVI ⁽³⁾	1.8	2.2

Note: Our ability to achieve our target PVI results are dependent upon the current and future market prices for natural gas and crude oil, costs associated with producing natural gas and crude oil and our ability to add reserves at an acceptable cost.

(1) Data based upon results of 2003 drilling program.

(2) Current completed well cost estimate.

(3) Assumes \$4.00 per Mcf flat pricing and gross EUR of 2.2 Bcfe per Overton well and gross EUR of 1.8 Bcf per Ranger well.

Note that the information contained on this slide constitutes a “forward-looking statement”.

(Slide 15)

2004 Exploration

This slide contains a map of Arkansas, Louisiana, Oklahoma, Texas and New Mexico with shading to denote areas of Company involvement. South Louisiana and New Mexico are further designated as areas of exploration. An exploded map of a portion of New Mexico details the River Ridge discovery. The Rio Blanco 33 #1 producing well, the Rio Blanco 33 #2 drilling well and the Rio Blanco #4-1 producing well are also shown.

- South Louisiana:

- 9/21 successful wildcats drilled since 1999.
- Plan to drill 2 wildcats in 2004.

- Gulf Coast exploration:
 - Reducing our exposure to high-risk exploration in South Louisiana.
 - 2004 program includes drilling 2 exploration wells.

- River Ridge prospect, Lea County, New Mexico:
 - Gross reserve potential of 50+ Bcfe.

Note that the information contained on this slide constitutes a “forward-looking statement”.

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How Have We Been Doing?

The graph contained on this slide shows F&D cost (\$/Mcf), reserve replacement (%) and PVI (\$/\$) after new management, a new E&P team and a new strategy were implemented in 1997.

	1997	1998	1999	2000 ⁽¹⁾	2001	2002	2003
F&D cost (\$/Mcf)	\$2.53	\$1.10	\$1.20	\$.99	\$1.11	\$1.02	\$1.18
Reserve replacement (%)	77%	129%	150%	196%	224%	209%	351%
PVI (\$/\$)	\$.56	\$1.17	\$1.07	\$1.30	\$1.40	\$1.33	\$1.42

Note: All metrics calculated exclude reserve revisions.

(1) PVI metrics calculated using pricing in effect at year-end (except for 2000 which was calculated at \$3.00 per Mcf natural gas price).

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Outlook for 2004

- Production target of 47.5 - 50.0 Bcfe in 2004 (estimated growth of 15 - 20%).

	2003 Actual	2004 Guidance NYMEX Price Assumptions	
	\$5.39 Gas ⁽¹⁾	\$5.00 Gas	\$6.00 Gas
	\$30.83 Oil ⁽¹⁾	\$26.00 Oil	\$26.00 Oil
Net Income	\$48.9 MM	\$69 - \$72 MM	\$87 - \$90 MM
EPS	\$1.43	\$1.90 - \$2.00	\$2.40 - \$2.50
Operating Income	\$97.3 MM	\$132 - \$135 MM	\$162 - \$165 MM
Cash Flow ⁽²⁾	\$132.3 MM	\$184 - \$187 MM	\$213 - \$216 MM
EBITDA ⁽²⁾	\$152.3 MM	\$200 - \$203 MM	\$230 - \$233 MM

Note: Per share estimates for 2004 assume 36.2 million weighted average diluted shares outstanding.

(1) The average realized prices for our gas and oil production, after the effect of commodity hedge losses and basis differentials, were \$4.20 per Mcf and \$26.72 per Bbl, respectively, in 2003.

(2) Cash flow and EBITDA are non-GAAP financial measures. See explanation and reconciliation of non-GAAP financial measures on pages 30 and 31.

Note that the information contained on this slide constitutes a "forward-looking statement".

(Slide 18)
Gas Hedges in Place Through 2005

This slide contains a bar chart detailing gas hedges in place by quarter for the years 2004 and 2005. A summary of these outstanding gas hedges is as follows:

	Type	Hedged Volumes	Average Price per Mcf (or Floor/Ceiling)	Percent of Total Production Hedged
2004	Swaps	7.2 Bcf	\$4.00	15 – 20%
	Collars	26.0 Bcf	\$3.92 / \$6.62	50 – 55%
2005	Swaps	11.0 Bcf	\$4.87	–
	Collars	19.0 Bcf	\$4.51/ \$7.01	–

Note: Southwestern has approximately 426,000 barrels of oil hedged at a fixed WTI price of \$28.39 per barrel in 2004 and 240,000 barrels of oil hedged at a fixed WTI price of \$30.05 per barrel in 2005.

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.
 - Accelerate Overton Development.
 - Accelerate Ranger Anticline Development.
- Maximize Cash Flow.
- Stay the Course with Our Focused Strategy.
- Deliver the Numbers.
 - Production and Reserve Growth.
 - Add Value for Every Dollar Invested.
- Continue to Tell Our Story.

(Slide 20)
Appendix

(Slide 21)
Financial & Operational Summary

This slide contains a table that summarizes the Company's financial and operational indicators.

	Quarter Ended March 31,		Year Ended December 31,			
	2004	2003	2003	2002	2001	2000 ⁽¹⁾
	(\$ in millions, except per share amounts)					
Revenues	\$119.8	\$98.7	\$327.4	\$261.5	\$344.9	\$363.9
EBITDA ⁽²⁾	59.3	39.8	152.3	99.8	134.6	103.2
Net Income	24.5	13.6	48.9	14.3	35.3	20.5
Cash Flow ⁽²⁾	56.5	36.7	132.3	79.8	112.7	82.4
Diluted EPS	\$0.67	\$0.47	\$1.43	\$0.55	\$1.38	\$0.82
Production (Bcfe)	11.4	8.9	41.2	40.1	39.8	35.7
Avg. Gas Price (\$/Mcf)	\$4.92	\$4.15	\$4.20	\$3.00	\$3.85	\$2.88
Avg. Oil Price (\$/Bbl)	\$28.43	\$27.69	\$26.72	\$21.02	\$23.55	\$22.99
Finding Cost (\$/Mcf) ⁽³⁾			\$1.18	\$1.02	\$1.11	\$0.99
Reserve Replacement (%) ⁽³⁾			351%	209%	224%	196%

(1) Before the effects of unusual and extraordinary items.

(2) Cash Flow and EBITDA are non-GAAP financial measures; see explanation and reconciliation of non-GAAP financial measures on pages 30 and 31.

(3) Excluding reserve revisions.

(Slide 22)
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)**

Burlington Resources

\$0.57

Southwestern Energy Company	\$0.62
Equitable Resources	\$0.63
EOG Resources	\$0.65
Kerr-McGee	\$0.69
ONEOK	\$0.72
Apache	\$0.79
Noble Energy	\$0.81
Amerada Hess	\$0.83
National Fuel Gas	\$0.84
Anadarko Petroleum	\$0.85
Murphy Oil	\$0.87
XTO Energy	\$0.89
Devon Energy	\$0.90
MDU Resources	\$0.95
Occidental Petroleum	\$0.99
Marathon Oil	\$1.01
Energen	\$1.15

This slide also contains a bar graph comparing SWN to its competitors in terms of drillbit F&D cost per Mcfe (3 year average).

**Drillbit F&D Cost
per Mcfe
(3 year average)**

XTO Energy	\$0.81
Occidental Petroleum	\$0.86
MDU Resources	\$1.03
Energen	\$1.05
Southwestern Energy Company	\$1.11
EOG Resources	\$1.19
Apache	\$1.32
Burlington Resources	\$1.37
ONEOK	\$1.47
Anadarko Petroleum	\$1.51
Kerr-McGee	\$1.63
Equitable Resources	\$1.67
Noble Energy	\$1.71
Marathon Oil	\$2.30
National Fuel Gas	\$2.32
Murphy Oil	\$2.76
Devon Energy	\$3.18
Amerada Hess	\$3.54

Source: John S. Herold Database

Note: All data as of December 31, 2001, 2002, and 2003.

(Slide 23)
Ranger Anticline

This slide contains a vertical cross-section of the Ranger Anticline area with shading to denote upper and lower borum.

- Thrust faulted/anticlinal Atokan sand play.
- Repeat sections of tight gas sands.
- Natural fractures that enhance productivity.

Note that the information contained on this slide constitutes a "forward-looking statement".

(Slide 24)
U.S. Gas Consumption and Sources

This slide displays U.S. gas production versus U.S. gas consumption from 1975 to the present. Net gas imports for the same period are also given. U.S. gas production has been basically flat since 1994.

Source: EIA

(Slide 25)
U.S. Gas Production Decline Rate

This graph portrays U.S. natural gas production history. The graph indicates a 29% 2004 decline rate.

Production Decline Rate of Base	
1990	17%
1991	17%
1992	16%
1993	18%
1994	19%
1995	19%
1996	20%
1997	21%
1998	23%
1999	23%
2000	25%

2001E	24%
2002E	27%
2003E	28%
2004E	29%

Utilized data supplied by IHS Energy; Copyright 1990 – 2004 IHS Energy

Chart prepared by and property of EOG Resources, Inc.; Copyright 2002 - 2004

(Slide 26)

U.S. Electricity Consumption on the Rise

This line graph shows an increase in U.S. electricity consumption in billion kilowatt-hours per month from 1990 to 2004.

Source: Edison Electric Institute

(Slide 27)

NYMEX Gas Prices

This line graph represents NYMEX gas prices in \$/Mcf from 2000 to 2004.

Source: Bloomberg

(Slide 28)

U.S. Gas Drilling

This line graph denotes the number of rigs drilling for gas through the period 1988 to 2004.

Source: Baker Hughes

(Slide 29)

West Texas Intermediate Oil Prices

This line graph shows the price of West Texas Intermediate oil in \$/Bbl for the years 2000 to 2004.

Source: Bloomberg

(Slide 30)

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 2004.

Source: Bloomberg

(Slide 31)

Explanation and Reconciliation of Non-GAAP Financial Measures: Cash Flow

Net cash provided by operating activities before changes in operating assets and liabilities is presented because of its acceptance 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. The company has also included this information because changes in operating assets and liabilities relate to the timing of cash receipts and disbursements which the company may not control and may not relate to the period in which the operating activities occurred. Net cash provided by operating activities before changes in operating assets and liabilities should not be considered in isolation or as a substitute for net cash provided by operating activities prepared in accordance with generally accepted accounting principles. The company does not forecast changes in operating assets and liabilities and, therefore, a reconciliation of the company's 2004 forecasted net cash provided by operating activities before changes in operating assets and liabilities to net cash provided by operating activities is not provided. However, the table below reconciles net cash provided by operating activities before changes in operating assets and liabilities with net cash provided by operating activities as derived from the company's historical financial information.

	12 Months Ended December 31,			
	<u>2003</u>	<u>2002</u>	<u>2001</u>	<u>2000</u>
Net Cash provided by operating activities	\$109,099	\$77,574	\$144,583	\$(28,917)
Add back:				
Change in operating assets and liabilities	<u>23,228</u>	<u>2,201</u>	<u>(31,886)</u>	<u>(24,286)</u>
Net cash provided by operating activities before				
Changes in operating activities and liabilities	<u>\$132,327</u>	<u>\$79,775</u>	<u>\$112,697</u>	<u>\$(53,203)</u> ⁽¹⁾

(1) Net cash provided by operating activities before changes in operating assets and liabilities for 2000 would have been \$58.1 million excluding the effects of unusual items for the Hales judgment and other litigation.

(Slide 32)

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 EBITDA as defined with net income as derived from the company's historical financial information.

	12 Months Ended December 31,			
	<u>2003</u>	<u>2002</u>	<u>2001</u>	<u>2000</u>
Net income	\$48,897	\$14,311	\$35,324	\$20,461 ⁽¹⁾
Depreciation, depletion and amortization ⁽²⁾	57,762	55,352	53,641	46,622
Net interest expense	17,311	21,466	23,699	24,689
Provision for income taxes	28,372 ⁽³⁾	8,708	21,917	11,457
EBITDA	<u>\$152,342</u>	<u>\$99,837</u>	<u>\$134,581</u>	<u>\$103,229</u> ⁽¹⁾

(1) Amounts exclude unusual and extraordinary items.

(2) Depreciation, depletion and amortization includes the amortization of restricted stock issued under the company's incentive compensation plan.

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

The table below reconciles EBITDA with net income assuming different NYMEX price scenarios and their corresponding estimated impact on the company's results for 2004, including current hedges in place, as of February 19, 2004:

	2004 Guidance	
	NYMEX Commodity Price Assumptions	
	\$5.00 Gas \$26.00 Oil	\$6.00 Gas \$26.00 Oil
	(\$ in millions)	
Net Income	\$69 - \$72	\$87 - \$90
Add back:		
Provision for income taxes – deferred	43 – 44	54 – 55
Interest expense	17 – 19	17 – 19
Depreciation, depletion, amortization	69 – 71	69 – 71
EBITDA	<u>\$200 – \$203</u>	<u>\$230 - \$233</u>