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 or earliest event reported) **February 18, 2003**

SOUTHWESTERN ENERGY COMPANY

(Exact name of registrant as specified in its charter)

Arkansas	**1-8246**	**71-0205415**
(State of incorporation or organization)	(Commission File Number)	(I.R.S. Employer Identification No.)

2350 N. Sam Houston Pkwy E., Suite 300, Houston, Texas 77032
(Address of principal executive offices, including zip code)

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

No Change
(Former name, former address and former fiscal year; if changed since last report)

Item 7 (c)

Exhibits

(99.1) Conference Call Summary dated February 18, 2003.

Item 9.

Regulation FD Disclosures

Southwestern Energy Company is furnishing under Item 9 of this Current Report on Form 8-K the information included as exhibit 99.1 to this report.

Note: The information in this report (including the exhibit) is furnished pursuant to item 9 and shall not be deemed to be "filed" for the purposes of Section 18 of the Securities Exchange Act of 1934 or otherwise subject to the liabilities of that section. This report will not be deemed an admission as to the materiality of any information in the report that is required to be disclosed solely by Regulation FD.

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, thereunto duly authorized.

SOUTHWESTERN ENERGY COMPANY
Registrant

Date February 19, 2003

BY: /s/ GREG D. KERLEY
Greg D. Kerley
Executive Vice President
and Chief Financial Officer

EXHIBIT INDEX

Exhibit No.	Description
99.1	Conference Call Summary dated February 18, 2003.

Southwestern Energy Company

Conference Call Summary

2002 Year-End Results Conference Call
Tuesday, February 18, 2003

<u>Chaired by</u>
Harold Korell
President, Chief Executive Officer and Chairman of the Board

<u>Korell:</u> Well, good morning, and thank you for joining us. With me today are Richard Lane, our Executive VP of the Exploration and Production Unit, and Greg Kerley, our Chief Financial Officer.

If you've not received a copy of our press releases that were filed yesterday, announcing our results for 2002, our intent to publicly offer five-and-a-half million shares of our common stock and our capital program and guidance for 2003, you can call (Sharon) at 281-618-4784, and she'll fax a copy to you.. Also, I would like to point out that many of the comments during this teleconference may be regarded as forward-looking statements that involve risk factors and uncertainties that are detailed in our Securities and Exchange Commission filings that were filed today. We also would warn you that these forward-looking statements are subject to risks and uncertainties, many of which are beyond our control. Although we believe the expectations expressed are based on reasonable assumptions, they are not guarantees of future performance, and actual results or developments may differ materially.

Well, I think the first order of business here today is to sum up 2002. Overall, 2002 was a good year. Our results with the drill bit continue to be impressive, with reserve replacement over 200 percent for the second year in a row and an excellent finding and development cost of $1.02 per Mcfe. 2002 marked our fourth straight year of successful drilling activity, with average production growth over that time of approximately seven percent per year, an average reserve replacement rate of 197 percent and an average finding and development cost of $1.07. We believe these results confirm that our plan is working to increase value for our shareholders.

Financially, our results in 2002 were lower than in 2001, primarily due to lower oil and gas prices. We recorded earnings of $0.55 per diluted share, compared to a record $1.28 per share last year. Although our production was slightly higher than in 2001, we were not able to overcome the impact of lower gas and oil prices. However, we are bullish about the current price environment and the combination of these prices, and the current level of service costs have motivated us to accelerate our infill drilling activity at our Overton Field.

As we announced yesterday, we are immediately moving forward with a five-and-a-half-million-share common stock offering. Proceeds from the offering will be used to accelerate the development drilling of our Overton Field in East Texas.

The results at Overton over the past two years have been exceptional. We've drilled 33 wells in the last two years, with 100 percent success. With an average finding and development cost of $0.68 per Mcfe over that time, we are clearly adding significant value. Assuming a gas price of $4.00 per Mcf, we're adding nearly $2 of discounted value for each dollar we invest in drilling at Overton. This success has compelled us to increase out activity at Overton over the next two years. Our current plan is to drill up to 100 wells at Overton, with four drilling rigs continuously running through 2004. We believe that the acceleration of the field's development will provide us with substantial growth in production and reserves over the next few years.

To sum this up, as a company we fought through some difficult issues from 1997 through 2000, while at the same time building a great team of people and projects. I think we've proven our abilities with the performance of the last three years. As a company, our opportunities are now exceeding our internally generated cash flow, and we believe it is prudent to accelerate our activity level. The equity offering allows us to do that. Now I'd like to turn the conference over to Richard Lane to discuss our E&P operations, then to Greg for comments on our financial plan.

Lane: Thank you Harold and good morning. 2002 was another successful year for the Company's E&P business. We can now reflect back over a four-year period and see a sustained period of strong operating results and growth. For 2002 we achieved a reserve replacement of 209% by adding 83.7 Bcfe of reserves at an average finding and development cost of $1.02/Mcfe excluding revisions. Our production for the year was up slightly over the prior year to 40.1 Bcfe, our third consecutive year of production growth despite the loss of production associated with divesting of our Mid-Continent properties in the fourth quarter. Over a four-year period we have achieved a 7% average production growth and, although we sold 32.9 Bcfe of reserves in the Mid-Continent, we ended the year at a record high of 415 Bcfe of proven reserves.

In total, we participated in 65 wells in 2002, of which 45 were successful and 4 were still in progress at year-end. In the Arkoma Basin, we were successful on 15 of the 25 wells drilled. We added 18.3 Bcfe of proved reserves in 2002, nearly replacing the 19.8 Bcf of production for this region. While our absolute well count was down year on year, we were able to achieve most of what we targeted for the Arkoma Basin through average higher net interest in the wells we did drill and through a very successful workover program. In 2003, we plan to invest $22.6 million in the Arkoma Basin, which includes drilling up to 30 wells and performing up to 60 workover projects.

In the Permian Basin, we reduced our capital investments to $5.4 million in 2002 and in 2003 we will invest approximately $4.8 million as we focus our drilling strategy in our Cherry Canyon and Devonian plays. We are currently completing our second horizontal well in our Birds of Prey prospect in Eddy County, New Mexico. The Eagle 4-1 well drilled a 2000 foot horizontal section in the Cherry Canyon Formation at 4,800'. This well offsets our Peregrine #1 horizontal well that we successfully drilled in the 2nd Quarter of 2002.

During 2002 in South Louisiana, we participated in 8 wells, of which 2 were successful. The 2 successful wells were small discoveries from our five-well exploration program in Cameron Parish. One of the discoveries, the Little Chenier Prospect, is currently producing at a gross rate of 1 million cubic feet per day. The West Grand Chenier test, the second well completed, was brought on production recently at a rate of one million cubic feet per day with plans to increase that rate. Southwestern holds a 25.7% working interest in both of these wells.

At the time of our last teleconference, we had just spudded our Piedmont prospect in Vermilion Parish. This well, which was targeting the Alliance sand at approximately 12,700 feet, penetrated the sand in a structurally favorable position. However, the sands were wet and we plugged the well in November.

Even though we did not have a significant discovery in South Louisiana in 2002, Southwestern's track record for this area since late 1999, continues to be very good with 8 successful tests out of 18 wells drilled. South Louisiana continues to be the primary focus area for our Exploration activities. In 2003, we plan to invest $21.7 million and drill up to 8 Company operated exploratory tests in this region. We are currently interpreting new data from our 135-square mile Duck Lake 3-D seismic project and expect to be drilling in the area in late 2003 and beyond. Interpretation of the 1000-square mile 3-D shelf data we purchased in 2002, is underway also and should provide prospect inventory for the future.

Of our 2003 South Louisiana prospects, two are currently drilling. The first prospect, Jericho, is a 14,300 foot Frio test in Lafayette Parish. Southwestern operates this well, which is currently drilling at 11,960 feet with a 35% working interest. The second active exploration test is our Shiloh prospect. This well is located in Vermilion Parish and is drilling at 12,435 feet on its way to the targeted Cris R sand at 14,000 feet. Southwestern also operates this well with a 62.5% working interest through completion and a 75% working interest thereafter. We expect both the Shiloh and Jericho prospects to be TD'd in approximately 30 to 45 days.

Our Overton Field in Smith County, Texas continues to provide us with a low-risk, multi-year drilling program. In 2002, we had 18 successful wells out of 18 drilled. These wells all targeted the Taylor series of sand in the Cotton Valley at approximately 12,000 feet. Since acquiring the field in 2000, we have drilled 33 wells and have increased gross production from 2 million cubic feet per day to 27 million cubic feet per day at year-end. Net annual production from the field was 5.9 Bcfe in 2002. Our proved reserves at the Overton Field increased to 111.0 Bcfe at year-end 2002, up from 57.6 Bcfe at year-end 2001 and 22.0 Bcfe at year-end 2000. We invested $33.6 million in the Overton Field during 2002 and recorded proved reserve additions of 56.4 Bcfe for a finding and development cost of $0.60 per Mcfe. We currently hold 16,500 gross acres in the field in addition to our South Overton farm-in of approximately 5800 gross acres. Our current average working interest in this field has increased to 97% after acquiring several small working interests in 2002. When we acquired Overton Field, it was primarily developed on 640-acre spacing, or one well per square mile. Other analogous Cotton Valley fields in the area have been drilled to 80-acre spacing, and in some cases to 40-acre spacing.

Because of our excellent results at Overton, we plan to significantly increase our activity in 2003. Our achievements in driving down the costs associated with drilling these wells and refining our completion procedures has set the stage for a highly economic multi-year development of this field. Continued downspacing should allow us to drill approximately 100 additional wells in the area over the next two years. We plan to invest approximately $78.0 million in East Texas during 2003, which includes drilling up to 47 new wells using four drilling rigs at the field. As Harold indicated, we believe the acceleration of our Overton Field will provide substantial growth in our production and reserves over the next few years. In addition to our activity at Overton in East Texas, we have three to four other Cotton Valley test wells planned as we seek to expand our activities in the East Texas basin.

Southwestern's total exploration and production capital budget for 2003 is $137.1 million, with approximately 83% allocated to drilling. The majority of our investments in 2003, approximately 73%, will be directed to the lower-risk part of our portfolio, in East Texas and in the Arkoma Basin. We project that Southwestern will participate in approximately 95 wells in 2003 as compared to 65 wells in 2002.

In summary, I am pleased with the results of our 2002 program and I am very excited about the opportunities ahead of us in 2003.

I will now turn it over to Greg Kerley who will discuss our financial results and talk about our guidance for 2003.

Kerley: Thank you, Richard and good morning. First, let me begin with a brief discussion of our results for the fourth quarter, after that I will discuss our year-end results. For the fourth quarter, we reported net income of $4.6 million, or $0.17 per share. This compares to net income of $7.4 million, or $0.29 per share, for the same period in 2001. Operating income and EBITDA were $12.8 million and $25.8 million during the fourth quarter, compared to $17.8 million and $31.8 million in the fourth quarter of 2001. Lower realized gas prices and a decline in production in the Company's E&P segment combined with increased expenses in the utility segment led to the declines. For the fourth quarter of 2002, our revenues decreased by $5.2 million due to our natural gas and crude oil commodity hedges, including $1.2 million related to the ineffectiveness of the hedge position. This compares to a revenue increase of $10.5 million from the Company's favorable commodity price hedges in the same period last year.

We reported net income for the year ended December 31, 2002 of $14.3 million, or $0.55 per share, compared to $35.3 million, or $1.38 per share in 2001. Operating income was $46.5 million and EBITDA was $99.8 million in 2002 compared to $82.7 million and $134.6 million, respectively, in 2001. Our revenues also declined in 2002 to $261 million, a decrease of 24% from $345 million in 2001. The decline in our financial results in 2002 was primarily due to our lower realized gas and oil prices.

We experienced slightly higher operating expenses in 2002 that were the result of marginally higher depreciation, depletion and amortization expense as well as higher insurance, pension and salary costs. Notably, however, during 2002 we were able to decrease our interest expense by

9% and our debt by $7.6 million due mainly to a favorable average interest rate on our debt of 5.7%.

Assuming NYMEX commodity prices of $4.25 per Mcf of gas and $24.50 per barrel of oil for 2003 which is the middle case of the three different NYMEX price scenarios that we have presented in our guidance information, the Company is targeting net income of between $33 – $36 million in 2003, up from $14.3 million in 2002. These estimates reflect projected oil and gas production for 2003 of 42 – 44 Bcfe, an increase of 5 – 10 percent over our 2002 production levels, and take into account the effect of the sale of the Company's Mid-Continent properties in 2002, which produced about 2.5 Bcfe annually. On the same basis, the Company expects its operating income to approximate $77 – $80 million and EBITDA to be approximately $135 – $138 million in 2003.

With respect to operating increase, the Company expects its total general and administrative expense to increase approximately $7.0 – $8.0 million in 2003, primarily due to increased pension, insurance and payroll costs The Company expects to record a pension expense of $3.0 – $5.0 million in 2003 as compared to less than a million dollars in 2002. Income taxes in 2003 are estimated at 38.0% and all are assumed to be deferred. The Company's net interest expense for 2003 is expected to be $18.0 – $20.0 million.

Operating income for the E&P segment was $36 million for 2002, down from $69.3 million for the same period in 2001, primarily the result of lower gas and oil prices. We realized an average gas price of $3.00 per Mcf during the year, down from $3.85 per Mcf a year ago. Going forward, our gas production for 2003 is 70% - 80% hedged at an average NYMEX floor price of $3.35 per Mcf.

Our E&P segment continues to benefit from some of the lowest operating costs in the industry. Lease operating expenses per Mcfe were $.45 per Mcfe for the 2002, flat with last year's production expenses. We expect our per unit lease operating expenses to significantly decrease in 2003 and fall in the range of $0.31 – $0.35 per Mcfe. The projected decrease in lease operating expense per unit is primarily due to the anticipated increased production from our Overton Field which is a lower average cost as compared to other areas and the sale of our Mid-Continent properties that had the highest average cost per unit of all our operating areas. Taxes other than income taxes were $0.19 per Mcfe in 2002, compared to $0.17 in 2001. In 2003, we expect those taxes to range between $0.24 – $0.28 per Mcfe due to higher commodity prices and the changing mix of production among taxing jurisdictions.

Our G&A expenses for our E&P segment were $.32 per Mcf equivalent for the year, compared to $.34 per Mcf equivalent in 2001. We expect our per unit G&A expenses to increase in 2003 and be in the range of $0.38 – $0.42 per Mcfe due to the expected increase in our pension, insurance and payroll costs that I previously noted. Depreciation, depletion and amortization expense for the E&P segment increased slightly during 2002 due to slightly higher production volumes and a higher amortization rate. The amortization rate for the full cost pool for 2002 was $1.16 per Mcfe, compared to $1.14 last year. We expect the amortization rate for the full cost pool for 2003 to remain fairly flat and be in the range of $1.14 – $1.18.

Operating income for the utility was $7.6 million in 2002, down 27% from $10.3 million last year. The decrease in operating income resulted from increased operating costs and expenses and reduced usage per customer due to customer conservation brought about by high gas prices in 2001. Operating costs and expenses increased in 2002 as compared to 2001 due to general inflationary effects and increased pension and insurance expenses. Weather during 2002 in the utility's service territory was 2% warmer than normal and 8% colder than the prior year. We filed an $11.0 million rate increase request with the Arkansas Public Service Commission in November 2002 and expect that any increase granted would be effective September 2003.

In 2003, we project the "gross margin" from our utility segment which represents the utility's revenues less its gas purchases to be approximately $50 – $55 million and the segment's operating income is expected to be approximately $7 – $9 million assuming normal weather.

Our operating income from marketing was $2.7 million on revenues of $131 million in 2002, compared to $2.7 million on revenues of $190 million in 2001. We marketed 45.5 Bcf in 2002, down from 49.6 Bcf in 2001. The decline in total volumes marketed in 2002 resulted primarily from the decline in volumes marketed to third parties. This reduction reflects our increased focus on marketing our own production and limiting the marketing of any third-party volumes in an effort to reduce our credit risk. Of the total volumes marketed, purchases from our exploration and production subsidiaries accounted for over two-thirds of our volume in 2002. The Company's gas marketing segment is expected to generate approximately $2.0 – $2.5 million in operating income in 2003.

Our capital expenditures for 2002 totaled $92.1 million, including $85.2 million invested in our exploration and production operations, $6.1 million for gas distribution system improvements and $800,000 for general purposes. Of the $85.2 million invested in our E&P program, approximately $18.2 million was invested in the Arkoma Basin, $33.6 million in East Texas, $5.4 million in the Permian and Mid-Continent areas, and $28.0 million in the Gulf Coast. Of the $85.2 million, approximately $15.5 million was invested in exploratory drilling, $46.1 million in development drilling and workovers, $9.1 million for leasehold and seismic, $3.1 million for producing property acquisitions, and $11.4 million in capitalized interest and expenses and other technology-related expenditures.

In 2003, we plan total capital expenditures of $145.6 million, consisting of 137.1 million for exploration and production, $7.7 million for gas distribution system improvements and $800,000 for general purposes. Of the $137.1 million E&P capital budget, approximately $97.2 million will be invested in development drilling and workovers, $16.1 million in exploratory drilling, $12.0 million for leasehold and seismic expenditures, and about $12 million in capitalized interest and expenses and technology-related expenditures. Our 2003 capital investment program is expected to be funded through cash flow from operations, our revolving credit facility, and the equity offering which we announced yesterday. We may adjust our level of future capital investments dependent upon our ability to access our credit facility and our level of cash flow generated from operations.

We depend on internally-generated funds and our revolving line of credit as our primary sources of liquidity. As of last Friday, we had $106.1 million of indebtedness outstanding under our

$125 million revolving credit facility. Net cash provided by operating activities was $77.6 million in 2002, compared to $144.6 million in 2001. The primary components of cash generated from operations are net income, DD&A, the provision for deferred income taxes and changes in our working capital. Net cash from operating activities provided 84% of our capital requirements for routine capital expenditures in 2002, and over 100% in 2001.

Thank you for joining us today. I would like to re-iterate that many of the comments during this teleconference may be regarded as forward-looking statements that involve risk factors and uncertainties that are detailed in our Form 10-K which was filed earlier today.

That concludes my comments, so now we'll turn back to the operator who will explain the procedure for asking questions.

Questions and Answers

1. First of all, regarding Overton - you've had some great success there and reserves have increased significantly. Currently, your reserve estimates are about 111 Bcf. How much of that would be proven developed?

Lane: Our percent of proved developed of that 111 Bcf is about 65 percent and we have 17 proven undeveloped locations on our books related to that field.

2. And are those 17 part of the 47 you're going to drill this coming year?

Lane: Well, some of those, as we drill over the next two years out there, some of those locations may be the specific locations that we drill, but what we see for the next two years, these 100 locations we've talked about, we see a reserve add associated with each one of those. So, in the event that we do drill a specific prior book location, we'll be in a position to be booking another one. So you can think of those 100 locations as all being reserve adds.

3. With respect to your increased capital budget and your increased production guidance, even if you factor out the property sales you did in the fourth quarter, production will grow in '03 by about 12 to 15 percent and yet your capital budget is increasing by about 60 percent. Is there some change in the underlying decline rate of your properties or is something else going on there?

Kerley: I think part of what you're seeing is the effect of the production growth really kicks in, in year two. It's really a two-year story. The drilling does start this year and we'll have production growth of a range of closer to what you're talking about and reserve growth, probably, of around 20 percent. But then in '04, we expect production growth in excess of 20 percent to 25 percent and reserve growth again of another 20 percent on top of there. So it really is a two-year program that really accelerates our growth.

4. In terms of your capital budget allocation, you have 10 million allocated to new projects. Can you just highlight what those new projects might be?

Korell: We always have our eye on some new opportunities. We are not planning to discuss, specifically, what those are, if for no other reason, basically for competitive reasons right now.

5. Those two South Louisiana wells that you're drilling – you may have given us this before, but who are your partners there, if you can say?

Lane: On our Jericho Prospect, you'll recall, that's out of our Eden 3 project and those partners would be Edge Petroleum and BTA out of Midland. And on the Shiloh Prospect, we have a higher interest there. We just have one private partner in there with us who is Petrogulf.

6. Richard, what's the difference between having success in the Arkoma Basin and drilling some dry holes there?

Lane: Well, usually a failure case there is that we don't encounter these highly strategraphic sand channels that we're pursuing. So that's usually your failure case there. You map them and they're very sinuous and you try to stack them up, but when you fail, it's usually because they're either not present or they're tight.

7. Have you moved from a two-rig program to a three or four-rig program in Overton yet and when do you plan on doing that?

Lane: We currently have four rigs in the field drilling now that we've ramped up through the month of January. So that is where we are and that's the level we plan to stay at for the remainder of the year.

8. So January went from two rigs to four.

Lane: Right.

9. What are the dry hole costs of a Jericho or Shiloh, rough range?

Lane: On a gross basis, Jericho's dry hole cost is about \$3.4 million, and Shiloh is about \$2.7 million.

10. I think you said you were going to drive eight wells in South Louisiana. I could have heard you wrong. That would imply six more after these two. Of the six, are they all Duck Lane and if so, when would you start your first Duck Lane well, please?

Lane: The remaining wells - and we're talking approximately eight, the ones that we would see going forward, would be a prospect in our Lake Salvador project area called Ben Nevis in the third quarter. And then Duck Lake of those remaining to be seen, possibly three wells to be drilled out of that project area and that would be in the second half of the year - third and fourth quarter.

11. You took some acreage, also, in East Texas that might have looked like an Overton to you guys. You were, I think, going to drill a well on it. Have you done that yet?

Lane: Well, we have a couple different areas that we've been purchasing new acreage. I think the one you're probably referring to is our Cayuga project. We currently have a well drilling out there right now that we hope to be testing here pretty soon. It's certainly not as low risk as Overton, but this first test we hope will tell us something about how we can pursue the rest of that acreage.

12. Where is that -what county, and how do you spell the prospect, please?

Lane: It's Cayuga – C-a-y-u-g-a. Near Cayuga Field in Anderson County. It's about 50 miles away Overton.

13. I was just curious what percentage of Overton has been down spaced?

Lane: We started out at about 640 acres per well. A few of those units, when we first purchased it, were downspaced at 320. We've done about 33 wells. So if you don't count what we have sitting here in front of us, we're probably somewhere in about the - about the 200- to 250-acre range.

Kerley: Thank you for joining us today, and feel free to call me or Brad Sylvester with any other questions you may have or information that you need.