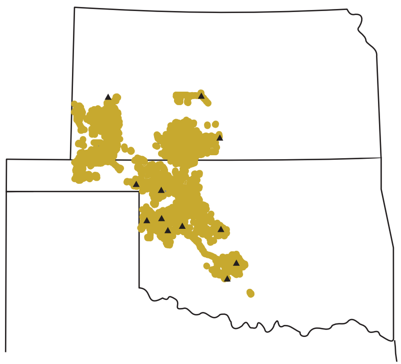
CHANGE

ONEOK

2005 ANNUAL REPORT

GATHERING AND PROCESSING

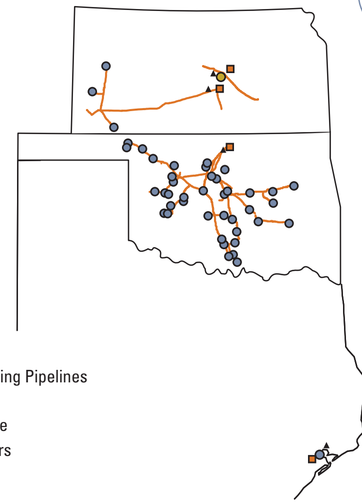
1



- ONEOK Gathering Systems
- ▲ ONEOK Processing Plants

NATURAL GAS LIQUIDS

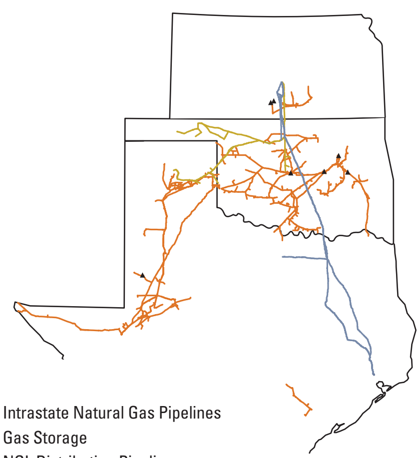
2



- ONEOK NGL Gathering Pipelines
- Processing Plants
- ONEOK NGL Storage
- ▲ ONEOK Fractionators
- NGL Hubs

PIPELINES AND STORAGE

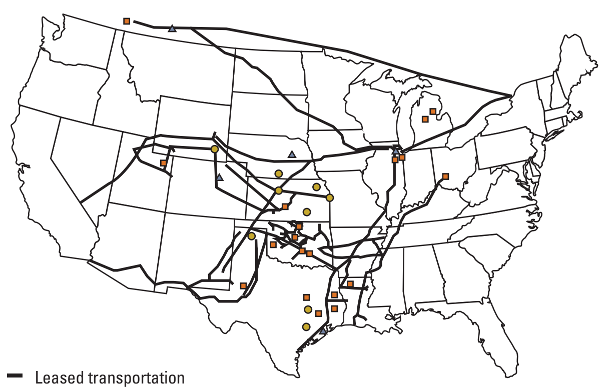
3



- ONEOK Intrastate Natural Gas Pipelines
- ▲ ONEOK Gas Storage
- ONEOK NGL Distribution Pipelines
- ONEOK NGL Gathering Pipelines

ENERGY SERVICES

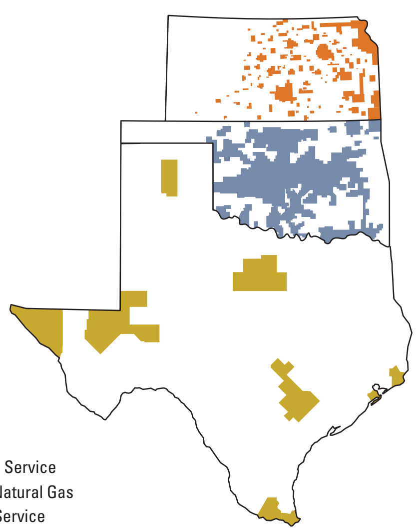
4



- Leased transportation
- Leased Storage
- ▲ Wholesale Offices
- Retail Offices

DISTRIBUTION

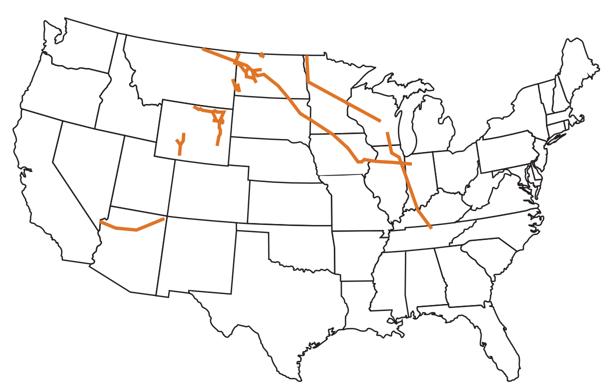
5



- Kansas Gas Service
- Oklahoma Natural Gas
- Texas Gas Service

NORTHERN BORDER PARTNERS, L.P.

6



- Pipelines

GATHERING AND PROCESSING

1

Statistics

12 active plants with total of 1.7 Bcf/d capacity
10,100 miles of gathering pipelines
89 MBbls/d of fractionation capacity

Results

(For The Year Ended Dec. 31)	2005	2004
Natural gas liquids and condensate sales ($000)	$ 671,865	$ 575,537
Natural gas liquids sales (MBbls/d)	49	51
Natural gas liquids produced (MBbls/d)	59	62
Gas sales ($000)	$ 877,049	$ 669,956
Gas sales (MMMBtu/d)	329	328
Total gas gathered (MMMBtu/d)	1,077	1,099
Total gas processed (MMMBtu/d)	1,117	1,172
Capital expenditures ($000)	$ 28,316	$ 23,067
Operating income ($000)	$ 395,439	$ 116,196

NATURAL GAS LIQUIDS

2

Statistics

4,600 miles of gathering and distribution pipelines
277 MBbls/d of gathering capacity
360 MBbls/d of distribution capacity
380 MBbls/d of fractionation capacity in four facilities
20.4 MMBbls of storage capacity

Results

(For The Year Ended Dec. 31)	2005	2004
Natural gas liquids and condensate sales ($000)	$2,361,488	$1,243,347
Natural gas liquids gathered (MBbls/d)(a)	191	-
Natural gas liquids sales (MBbls/d)	207	109
Storage and fractionation revenues ($000)	$ 98,887	$ 13,151
Natural gas liquids fractionated (MBbls/d) (a)	292	-
Capital expenditures ($000)	$ 12,220	$ 9,264
Operating income ($000)	$ 43,369	$ 14,835

(a) Data presented for 2005 represents the per day results of operations from July 1, 2005.

PIPELINES AND STORAGE

3

Statistics

5,600 miles of natural gas transmission and gathering pipelines
2,500 miles of natural gas liquids gathering and distribution pipelines
2.9 Bcf/d of peak natural gas transportation capacity
355 MBbls/d of peak NGL transportation capacity
1.3 Bcf/d average daily throughput
Supply/market connections via 96 pipelines, 37 processing plants and 139 producing fields
51.6 Bcf of active working storage capacity
1.0 Bcf/d maximum storage injection
1.9 Bcf/d maximum storage withdrawal
Pipeline connections to storage: 1 interstate, 12 intrastate

Results

(For The Year Ended Dec. 31)	2005	2004
Transportation and gathering revenues	$151,490	$101,950
Natural gas transported (MMcf)	486,635	432,844
Natural gas liquids transported (MBbls/d) (a)	187	-
Natural gas liquids gathered (MBbls/d) (a)	53	-
Capital expenditures ($000)	$ 15,719	$ 12,287
Operating income ($000)	$ 84,586	$ 59,785

(a) Data presented for 2005 represents the per day results of operations from July 1, 2005.

ENERGY SERVICES

4

Statistics

86 Bcf of leased storage capacity
2.3 Bcf/d of storage withdrawal rights
1.6 Bcf/d of storage injection rights
1.9 Bcf/d of leased transportation capacity

Results

(For The Year Ended Dec. 31)	2005	2004
Energy and power revenues ($000)	$8,345,091	$2,720,629
Energy trading revenues, net ($000)	$ 12,680	$ 113,814
Natural gas marketed (Bcf)	1,191	1,073
Operating income ($000)	$ 165,691	$ 139,191

DISTRIBUTION

5

Statistics

The largest natural gas distributor in Kansas and Oklahoma, and the third largest in Texas
Serves more than two million customers
Diversified regulatory environment – state commissions or local municipalities

Results

(For The Year Ended Dec. 31)	2005	2004
Total throughput (MMcf)	451,996	442,812
Capital expenditures ($000)	$143,765	$142,515
Number of customers (Average)	2,018,900	2,008,835
Customers per employee (Average)	689	664
Operating income ($000)	$113,912	$110,227

NORTHERN BORDER PARTNERS, L.P.

6

ONEOK has an 82.5 percent general partner interest in Northern Border Partners, L.P.

Northern Border Partners, L.P. owns:

70 percent interest in Northern Border Pipeline
100 percent interest in Midwestern Gas Transmission
100 percent interest in Viking Gas Transmission
33.3 percent interest in Guardian Pipeline held through Viking
100 percent interest in Black Mesa Pipeline

Statistics

2,320 miles of interstate natural gas pipelines (regulated)
5 gas processing plants
396,000 acres of dedicated reserves
273-mile coal slurry pipeline
Transported approximately 20 percent of all Canadian gas imported into the U.S. through Northern Border Pipeline

ONEOK Distribution Companies provides natural gas to more than two million homes and businesses in Oklahoma, Kansas and Texas.

ONEOK Energy Companies gathers, processes, fractionates, stores, transports and nationally markets natural gas and natural gas liquids. Its operations are in the heart of the nation's natural gas production basins.

CONTENTS

FINANCIAL HIGHLIGHTS

Year Ended December 31	2005	2004	2003
Consolidated Financial Information ($000)			
Net Margin	1,338,154	1,137,217	1,084,818
Operating income	798,972	443,652	427,855
Income from continuing operations	403,148	224,673	206,449
Income from operations of discontinued component, net	(6,180)	17,505	10,185
Net income	546,545	242,178	112,488
Capital expenditures	250,493	264,110	215,148
Number of employees at year end	4,559	4,657	4,342
Common stock data			
Shares outstanding at year end	97,654,697	104,106,285	95,194,666
Data per common share			
Earnings from continuing operations - diluted	$ 3.73	$ 2.13	$ 2.05
Net earnings - diluted	$ 5.06	$ 2.30	$ 1.22
Dividends paid	$ 1.09	$ 0.88	$ 0.69
Book value at year end	$ 18.38	$ 15.42	$ 13.04
Market price range			
High	$ 35.72	$ 28.90	$ 22.22
Low	$ 26.63	$ 19.80	$ 16.44
Market price at year end	$ 26.63	$ 28.42	$ 22.08
Return on average common equity from continuing operations	23.7%	15.8%	17.9%
Return on average total shareholders' equity from continuing operations	23.7%	15.8%	15.8%

LETTER TO SHAREHOLDERS

CHANGE.

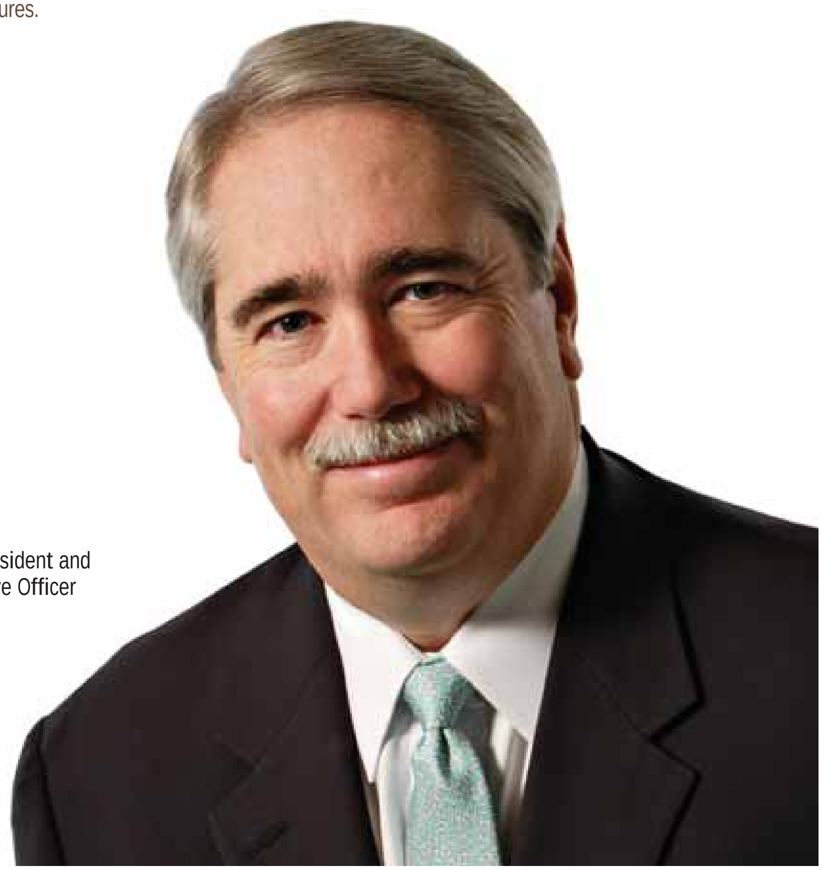
Change is a fact of life for everyone and everything – large corporations included. At ONEOK, we do not stand idly by, wait for change to happen and then worry how we should react. Instead, we anticipate, create and embrace change and seize opportunities.

Since I wrote to you a year ago, we have captured remarkable opportunities that will provide exceptional value for ONEOK shareholders. Equally important, we worked diligently and effectively throughout the year to produce operating results that, on a whole, were outstanding.

Clearly, we enjoyed a great and eventful year. In my almost 32 years with this organization, I have never been more excited about its future. I write this with pride and confidence as we move toward the company's one-hundredth anniversary this fall.

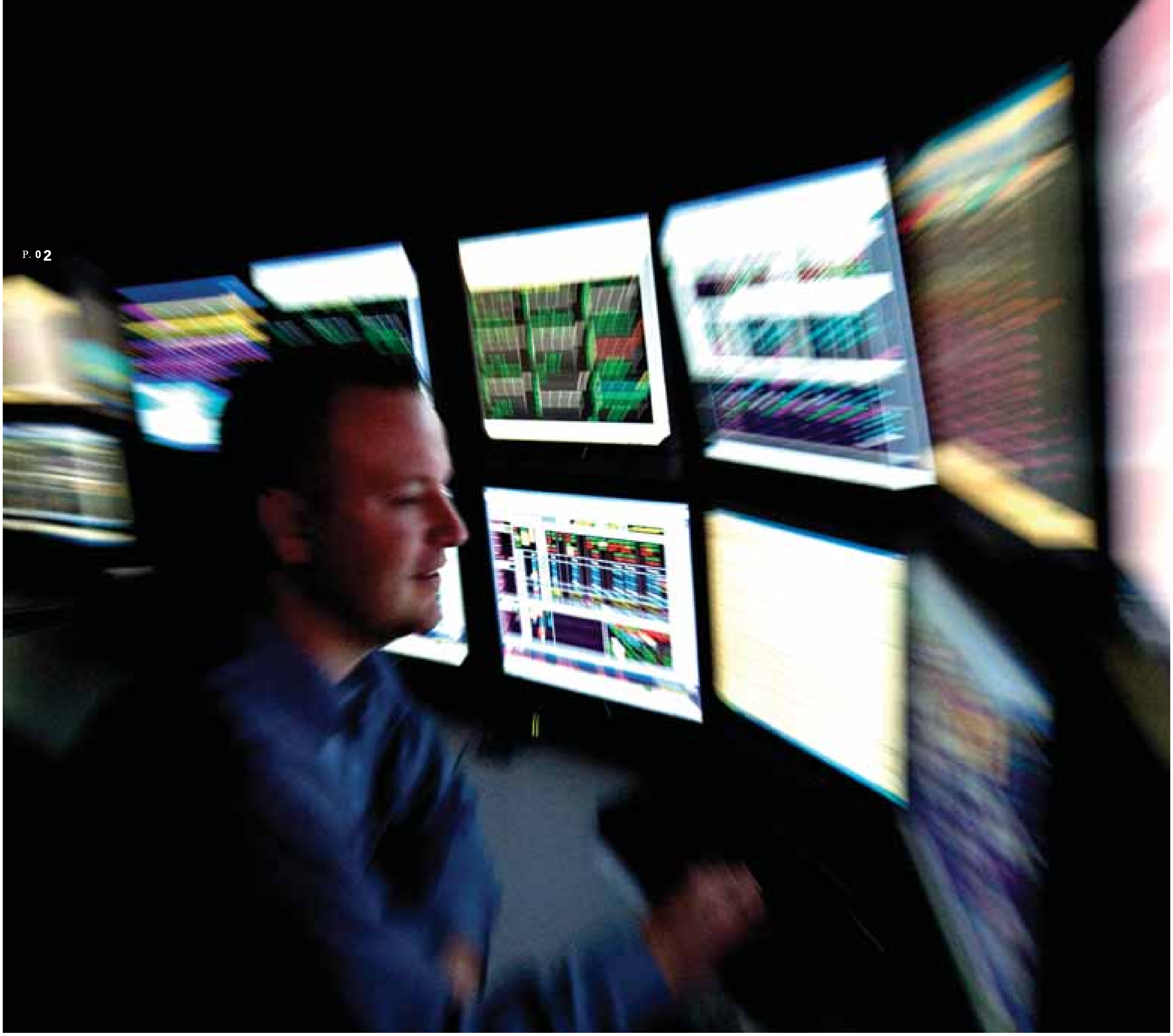
DURING 2005 WE:

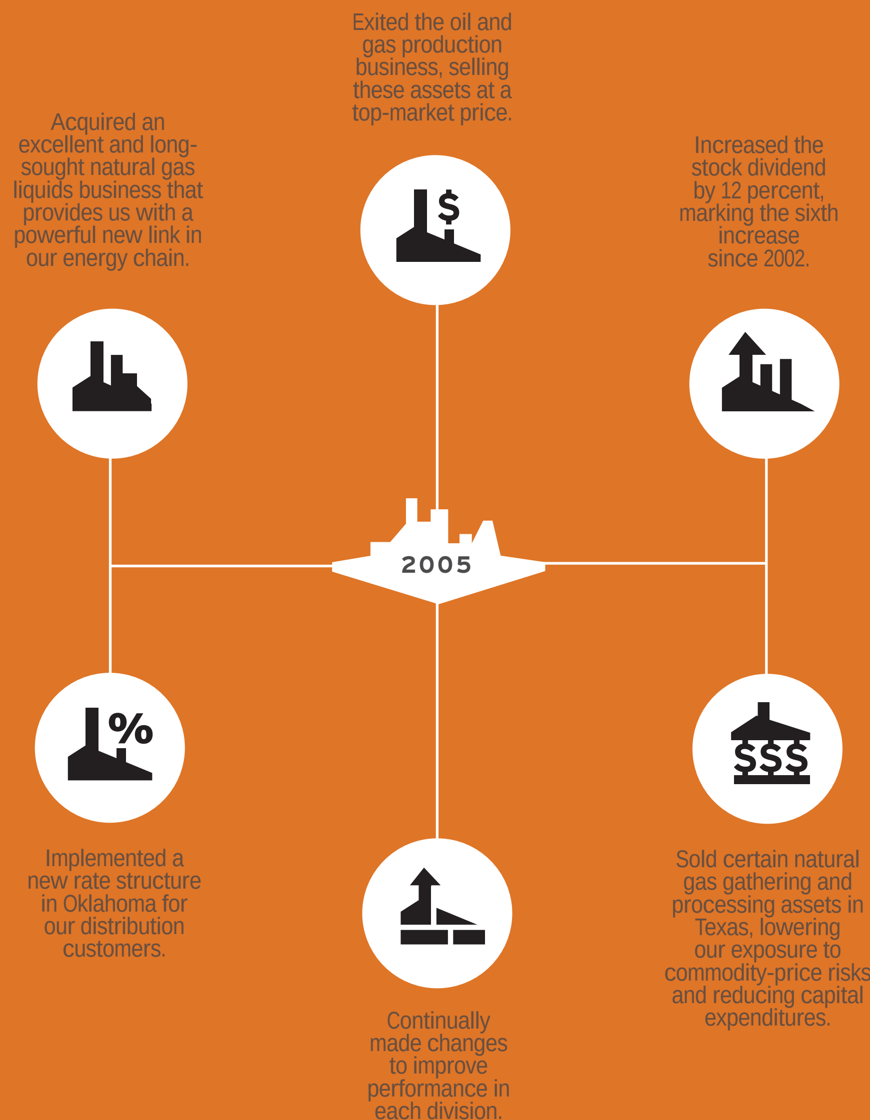
- Acquired an excellent and long-sought natural gas liquids business that provides us with a powerful new link in our energy chain.
- Exited the oil and gas production business, selling these assets at a top-market price.
- Increased the stock dividend by 12 percent, marking the sixth increase since 2002.
- Implemented a new rate structure in Oklahoma for our distribution customers.
- Continually made changes to improve performance in each division.
- Sold certain natural gas gathering and processing assets in Texas, lowering our exposure to commodity-price risks and reducing capital expenditures.



David Kyle
Chairman, President and
Chief Executive Officer

DURING
2005 WE:




Exited the oil and gas production business, selling these assets at a top-market price.
Acquired an excellent and long-sought natural gas liquids business that provides us with a powerful new link in our energy chain.
Increased the stock dividend by 12 percent, marking the sixth increase since 2002.
2005
Implemented a new rate structure in Oklahoma for our distribution customers.
Sold certain natural gas gathering and processing assets in Texas, lowering our exposure to commodity-price risks and reducing capital expenditures.
Continually made changes to improve performance in each division.

$165.7 MILLION

Energy Services – the marketing and trading segment – provided stellar performance, with operating income of $165.7 million, compared with $139.2 million in 2004.

$84.6 MILLION

Pipelines and Storage also had a superior year, recording $84.6 million in operating income, compared with $59.8 million in 2004.

$395.4 MILLION

Gathering and Processing reported operating income of $395.4 million (including the gain from the sale of the Texas gathering and processing assets), compared with $116.2 million a year ago.

$113.9 MILLION

Our three natural gas Distribution Companies performed solidly and made a series of changes designed to provide better service and to ensure an equitable and stable return. Its total operating income was $113.9 million in 2005, compared with $110.2 million the previous year.

$43.4 MILLION

Natural Gas Liquids, our new Energy Companies segment, reported operating income of $43.4 million – largely the result of the acquired NGL business we began operating in July – compared with $14.8 million from existing NGL-related operations in 2004.

PERFORMANCE REVIEW Net income for 2005 was $546.5 million, or $5.06 per diluted share of common stock, compared with $242.2 million, or $2.30 per diluted share, the previous year. The year-end results included after-tax gains from the sale of the oil and gas production assets and the sale of the Texas gathering and processing assets, partially offset by the impairment related to the pending sale of a small electric-power plant in Oklahoma.

When you remove these nonrecurring items, the net income for 2005 was $267.5 million, or $2.47 per diluted share of common stock, still reflecting a very good year.

ONEOK's Energy Companies performed very well across the board. Its operating income was a record $689.1 million, compared with $330 million in 2004.

HERE IS A SNAPSHOT OF THOSE OPERATIONS:

- **Gathering and Processing** reported operating income of $395.4 million (including the gain from the sale of the Texas gathering and processing assets), compared with $116.2 million a year ago.
- **Natural Gas Liquids**, our new Energy Companies segment, reported operating income of $43.4 million – largely the result of the acquired NGL business we began operating in July – compared with $14.8 million from existing NGL-related operations in 2004.
- **Pipelines and Storage** also had a superior year, recording $84.6 million in operating income, compared with $59.8 million in 2004.
- **Energy Services** – the marketing and trading segment – turned in a stellar performance, with operating income of $165.7 million, compared with $139.2 million in 2004.
- **Our three natural gas Distribution Companies** performed solidly and made a series of changes designed to provide better service and to ensure an equitable and stable return. Total operating income was $113.9 million in 2005, compared with $110.2 million the previous year.

TEAM EFFORT The past year's results reflect the decisions made and the work accomplished daily by ONEOK employees, from the most remote field site to the corporate headquarters. Our individual and collective focus is on doing the job well and seeking and sharing ways to do it better.

Our employees literally have a stake in the company. Like our investors, from the smallest to the largest, they want to see the share price grow. We ground our decisions on creating long-term value, which we believe ultimately will be rewarded.

LOOKING TO THE FUTURE Just as we were financially buttoning up 2005 and preparing to release our fourth-quarter and year-end earnings report, ONEOK and Northern Border Partners on February 15 announced a multifaceted transaction precisely targeted at increasing shareholder and unit holder value for both companies. As those who have followed our company know, in November 2004 we became the majority general partner of Northern Border Partners, one of the largest publicly traded master limited partnerships.

Once the historic-level transaction has been implemented, Northern Border Partners will be ONEOK's primary source for growth, with some very distinct advantages.

ACQUIRING THE 'JEWEL'

OPPORTUNITIES TO ACQUIRE A COMPLETE NGL BUSINESS OF THIS CALIBER AND SCOPE ARE FEW AND FAR BETWEEN. THE $135 BILLION ACQUISITION WAS THE LARGEST IN ONEOK HISTORY.

ACQUIRING THE 'JEWEL' Every once in a while we are able to acquire a business that we have had our eyes on for years. I relate this to the child who has his face pressed against the storefront window. The youngster is peering at something he very much wants to own and then learns that the item actually can be obtained. This pretty well describes how we felt when we acquired Koch Industries' entire natural gas liquids business last summer.

Opportunities to acquire a complete NGL business of this caliber and scope are few and far between.

The $1.35 billion acquisition was the largest in ONEOK history. To put this in perspective, the amount would have represented more than 100 percent of our company's assets two decades ago and was nearly one-fifth of ONEOK's asset base on July 1 when we announced completion of the deal. We acquired these assets at a fair price, and I believe, over the long term, they will prove to be a cornerstone of our future growth. However, the dollars invested aren't the "news" – the glove-like fit, quality, capabilities, potential and human talent we acquired are the real story.

Our own people have described this former privately owned and operated NGL business as a "jewel." The system allows us to participate in the NGL link of the value chain downstream of our processing plants. Eleven of our 13 processing plants already were connected to the acquired NGL system and represented 15 percent of its upstream business. An additional 54 processing plants feed into the system. In fact, 90 percent of all the gas plants in the Anadarko, Arkoma and Hugoton basins are connected to this business.

A reversible NGL pipeline – part of the acquisition package – connects two of the nation's largest NGL market centers at Mont Belvieu, on the Gulf Coast near Houston, and at Conway, in central Kansas. This pipeline allows us to take advantage of product-price differentials as they arise at the two points.

Shortly after we acquired these Koch assets, we opened discussions with no fewer than nine processing plant operators in connection with anticipated incremental volumes, some of which will require construction of processing plants to accommodate new drilling, particularly in Oklahoma. We initially thought that the volume increase could amount to 20,000 barrels per day, but are now optimistic that volumes could increase even more. As necessary, our NGL facilities can and will be expanded to accommodate the growth in volumes.

Demand for NGL products – ethane, propane, butane, isobutane and natural gasoline – is growing nationally. Approximately half of the NGL production in this nation is dedicated to the manufacture of petrochemicals, the demand for which is outpacing other uses, such as heating.

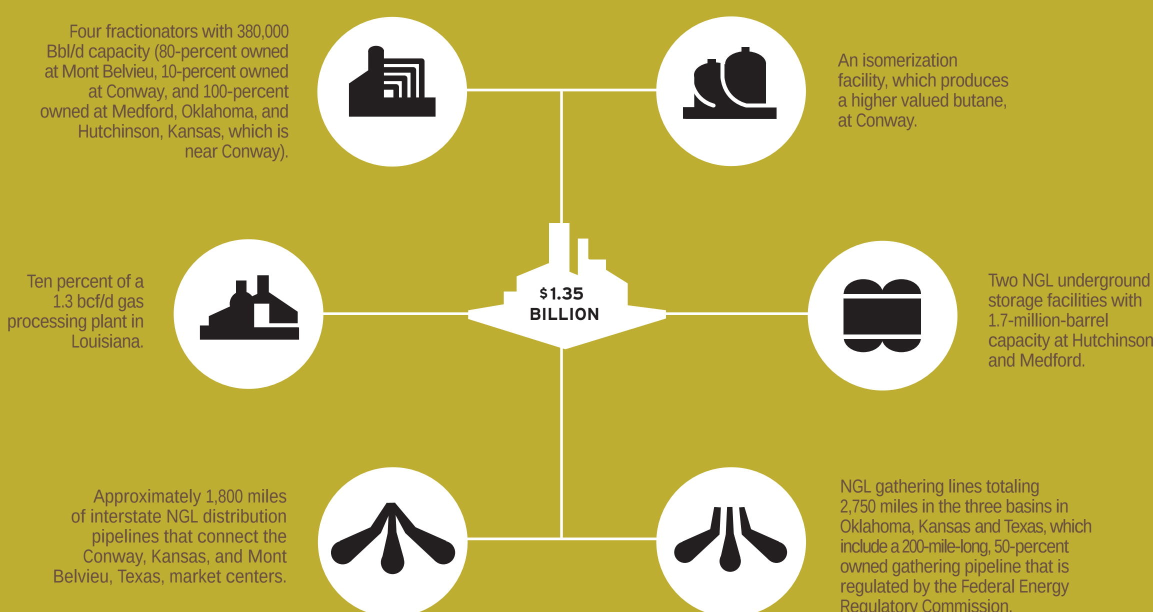
The addition of this NGL link in our value chain significantly lowers our risk profile, because more than 80 percent of the revenue is fee based.

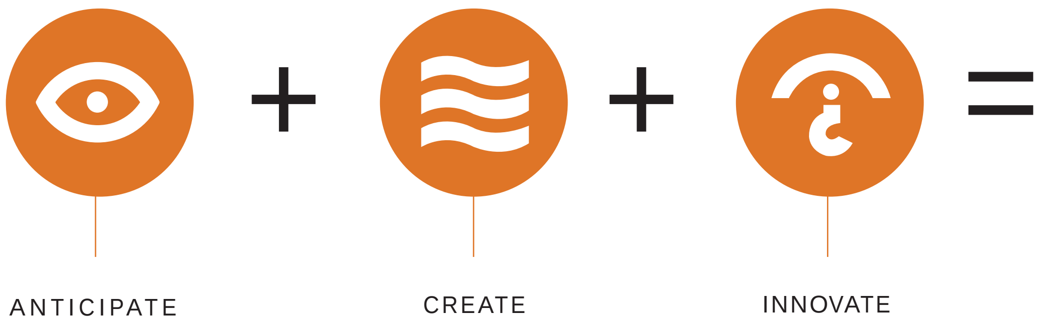
HERE ARE THE ACQUIRED ASSETS:

- Four fractionators with 380,000 Bbl/d capacity (80-percent owned at Mont Belvieu, 10-percent owned at Conway, and 100-percent owned at Medford, Oklahoma, and Hutchinson, Kansas, which is near Conway).
- An isomerization facility, which produces a higher valued butane, at Conway.
- Two NGL underground storage facilities with 1.7-million-barrel capacity at Hutchinson and Medford.
- Approximately 1,800 miles of interstate NGL distribution pipelines that connect the Conway, Kansas, and Mont Belvieu, Texas, market centers.
- NGL gathering lines totaling 2,750 miles in the three basins in Oklahoma, Kansas and Texas. These assets include a 200-mile-long, 50-percent owned gathering pipeline that is regulated by the Federal Energy Regulatory Commission.
- Ten percent of a 1.3 bcf/d gas processing plant in Louisiana.

Integration of this new business went smoothly; we understand the business and it was a natural extension of our existing operations. We have tucked the gas processing and pipeline pieces of the acquired assets inside appropriate Energy Companies segments.

At the end of the day, best-quality assets are no better than the people who run them. So, I'll close this discussion by mentioning the talent we inherited from this acquisition – 191 men and women trained to operate these facilities at a high standard. Both they and this NGL business fit extremely well with the ONEOK culture and work ethic.





SELLING ASSETS Never fall in love with your assets. At ONEOK, we take that adage to heart. We routinely examine our assets to determine if they still fit – or can be made to fit – our strict strategic plan. As a result of this ongoing process, we chose to sell two substantial operations in 2005.

In September, we sold all of our oil and gas production assets in Oklahoma and Texas for $645 million and exited that business. Proceeds were used to reduce debt.

Less than three months later, we announced that we had completed the sale of certain Texas gathering and processing assets for $527 million. This sale generated an after-tax book gain of $162 million, or $1.50 per diluted share of common stock, which was recorded as income from continuing operations in the fourth quarter.

Neither of these divestitures, incidentally, was related to our mid-year acquisition of the NGL business.

We have long believed that we needed to grow our oil and gas production business in order to reach more appropriate economies of scale – or we needed to sell it. During 2004, our capital expenditures in this enterprise had exceeded its operating income. Candidly, we did make attempts to grow this business, but competitive bids on properties we were interested in fell outside of our value-for-dollar parameter. We timed the sale at the high-water mark for these four production fields in Oklahoma and Texas.

The divested gathering and processing assets geographically did not fit with our cohesive gathering and processing operations elsewhere and were relatively expensive to operate and maintain. Also, this system produced the lowest margin of any of our systems and had considerable exposure to commodity-price risks.

RESTRUCTURING CONTRACTS Our Gathering and Processing segment has worked diligently over the past three years to renegotiate and realign contracts on a system-wide basis with our producer customers. As a result, our mix of contracts by volume positions us for more reliable income streams while also retaining upside potential.

Simply put, we are pleased with our current position.

My final thought on this topic: Gathering and Processing is continually aligning itself with its producer customers to provide a beneficial relationship for them and us. It's working.

IMPLEMENTING NEW RATES In late July, Oklahoma Natural Gas implemented new rates for its more than 800,000 customers, marking the first base rate increase since 1995. We had sought additional annual revenues of $99.4 million; the Oklahoma Corporation Commission approved a $57.5 million increase.

Since 2000, Oklahoma Natural Gas had already invested more than $190 million in its rate base, and its operating expenses had increased by more than $50 million annually. We believe these and other facts presented to the commission warranted the rate increase we requested. However, a lot of time had lapsed since we sought a full rate-case review, and we intend to file for necessary future reviews in a more timely manner.

The new Oklahoma Natural Gas rate structure moved more of the fixed cost into the service charge, which provides a more stable revenue stream. Previously, approximately one-third of the fixed cost was in the service charge and approximately two-thirds was in the variable portion; now, those figures are reversed, reducing both the customer's and the company's exposure to weather variability. Also, a voluntary-choice,

”We remain on the lookout for new opportunities *that fit.*“

STAYING HEALTHY

two-tiered rate structure was introduced with the potential to benefit low-volume and high-volume customers.

Oklahoma Natural Gas, the largest distribution system in that state, continued its innovative program that allows customers to select a fixed, per-unit price for the gas they consume. The voluntary program, which has been well received and will be repeated in 2006, protects customers from gas-price volatility.

At Oklahoma Natural Gas and our two other distribution companies, Kansas Gas Service and Texas Gas Service, we must balance our service obligations to our two million customers with our obligation to provide an appropriate return to ONEOK's shareholders.

We are sensitive to the burden that higher gas prices place on a significant number of customers. In February 2006, the ONEOK Foundation allocated a total of $1 million to The Salvation Army in Oklahoma and Kansas and to a variety of organizations in Texas to help customers in need pay their energy bills in all three of the states we serve. We make no money on the gas portion of the customer's bill – it's a pure pass-through cost – but the higher gas costs create a difficult situation for certain customers and it also affects us, since we do not recover our actual costs when bills go unpaid.

Texas Gas Service in November requested rate increases in the Port Arthur area and in north Texas. These requests will be resolved in 2006.

Kansas Gas Service will request a general rate increase after a three-year moratorium expires in May. This system, the largest in that state, serves approximately 640,000 customers.

For the first time, our three distribution companies operated under a single management structure in 2005. We expect this integration to provide more effective operations, better customer service, and position us for fair returns on our investments. Cross-jurisdictional teams and task forces in all three states are working together to make this happen.

In mid-summer 2006, a customer-information-system platform deployed in Kansas in 2003 and Texas in 2004 will go into operation in Oklahoma. This is but one example where standardization is bringing faster and better information to our customers.

Our distribution companies are capital-intensive businesses. Going forward, we must continue to provide good value and reliable service to the customer while pursuing a fair return on our investments.

STAYING HEALTHY As a result of “levering up” our balance sheet in connection with the acquisition of the natural gas liquids business, we closed 2005 with a long-term debt-to-equity ratio of 53 percent, which was still 1 percent lower than when the year began. As I write this, we had already managed to work it down to 47 percent.

Ideally, we would like to see our debt evenly split with equity. But we have preferred to leverage up our balance sheet – versus selling assets we do not necessarily want to sell or issuing equity – from time to time rather than bypass prime opportunities that fit our strategy of growing earnings by acquisition and geographical expansion.

The long and short of it is this: We were financially sound throughout the year, and we are financially sound going forward. We remain on the lookout for new opportunities *that fit.* A section following my letter provides a look at various aspects of ONEOK's financial health, including discussion on the 16.1 million corporate units that were converted to equity in February 2006. You also will see sections on our Energy and Distribution companies there.

TRANSFORMING OUR COMPANY

ONEOK+
NORTHERN BORDER PARTNERS

TRANSFORMING OUR COMPANY In February 2006, ONEOK entered into the largest and perhaps the most significant series of transactions in its century-long history. The effect, we believe, will provide both immediate and long-term value to ONEOK shareholders.

As a key part of the multifaceted deal, we have agreed to transfer all of our gathering and processing, natural gas liquids, and pipeline and storage businesses to Northern Border Partners, a master limited partnership. These assets represent the core physical field operations of ONEOK's Energy Companies. We will retain Energy Services.

After long study, we decided in 2004 that Northern Border Partners could become ONEOK's future growth engine. Why? Because Northern Border Partners can compete more effectively than we can with these same core assets. This competitive edge comes from the lower cost of capital available to master limited partnerships by way of tax advantages distinct to them.

BRIEFLY, HERE ARE SOME OTHER ADVANTAGES:

- Northern Border Partners can issue equity, or units, when necessary for growth without diluting ONEOK stock.
- ONEOK's stock will be more clearly valued as a result of these changes. Also, master limited partnerships typically are valued higher than corporations.
- ONEOK, through the partnership, will dramatically increase its footprint and reach beyond the gas reserves of the Mid-Continent.

In exchange for the transferred assets, Northern Border Partners will pay us $1.35 billion in cash – the exact sum we paid for the natural gas liquids business last year. It also will issue to us 36.5 million limited partner units, which are traded on the New York Stock Exchange under the symbol NBP. These units, coupled with a related general partner interest contribution, are valued at $1.65 billion. In other words, this is a $3 billion deal and the largest in our almost 100-year history.

Coupled with our existing 2.73 percent interest in the partnership, ONEOK will own 45.7 percent of Northern Border Partners. Formed in 1993, the partnership owns pipelines and other midstream energy assets, largely in the upper Midwest. It is a leading transporter of Canadian gas into the United States.

As a key part of the agreements, ONEOK will pay $40 million to TransCanada Corporation in exchange for its 17.5 percent general partner interest in Northern Border Partners. This will increase ONEOK's general partner interest to 100 percent.

In other words, we will control our own destiny.

Operationally, the change at ONEOK will be almost transparent. Our same talented people will continue to manage and run the transferred assets.

HONORING THE LEGACY I hope that after reading this letter you are as enthused as I am about ONEOK's future. In the first quarter of this year, *FORTUNE* magazine recognized ONEOK as one of America's "most-admired" companies. We are truly gratified by this honor. In the broad energy sector, our company's rankings were number-one in the categories of social responsibility, use of corporate assets, and quality of management and products/services.

On October 12, 2006, we will celebrate this company's one-hundredth anniversary. It all started when Oklahoma Natural Gas began laying a pipeline from the once-mighty Glenn Pool Field south of Tulsa to bring new supply to customers. At the time, natural gas was seen by many oil field operators as a nuisance – wow, have times changed.

From my viewpoint, there is a large, personal responsibility to preserve this legacy and to see that it goes forward in a manner that makes us not only pleased but proud. Several great chairmen have come before me, and I feel their influence each time I make a choice for yet another change.

Our century of service places us in a rarefied position as a Fortune 500 company that has remained and thrived in the same industry it originated in, dating back to a time when motorized vehicles were an uncommon sight, radio had not been heard, and natural gas was not yet a household word. Our century of service has involved welcoming and creating change, making the right decisions, and, most important, doing the right things day in and day out.

We at ONEOK protect this great legacy. We are the keeper of the flame. All of us are working for the future of ONEOK – and that future is unfolding now.

David Kyle
Chairman, President and
Chief Executive Officer

Tulsa, Oklahoma March 15, 2006

“Our focus is to ensure that all of the assets work together, not just work. And it’s to make sure we own the right assets, not just assets.“

JOHN W. GIBSON
President,
ONEOK Energy Companies

ENERGY

HIGHLIGHTS AND FEATURES

• Our Energy Companies achieved operating income of $689.1 million in 2005, which includes the gain from the sale of certain gathering and processing assets in December. Performance of each of the four segments showed improvement ranging from significant to dramatic. The largest single gain in operating income — $28.5 million — came from Natural Gas Liquids, largely reflecting the operations of an NGL business acquired at mid-year. Energy Services, which derives more than 84 percent of its earnings from the physical marketing business, showed an operating income increase of $26.5 million. Pipelines and Storage's operating income increased by $24.8 million; and Gathering and Processing's operating income increased by $15.0 million.

• In July we announced completion of a $1.35 billion acquisition of Koch Industries' NGL business, (discussed in some detail in our chairman's letter to shareholders). We quickly formed a new Natural Gas Liquids business segment and, by the fourth quarter, we entered talks with producers to connect up to 24,500 incremental barrels to this business during 2006. The acquisition's strength was reflected elsewhere: Pipelines and Storage reported a year-over-year increase in net margin of $45.1 million, with $26.4 million of that amount attributed to the natural gas liquids gathering and distribution pipelines acquired last summer.

• In December we announced that we had completed the sale of our gathering and processing assets in the Texas Panhandle. These assets represented our smallest region by volume, by margin and by NGL production. We recorded a $264.2 million gain on the sale, which was included in Gathering and Processing's fourth-quarter income.

• Renegotiation of several key natural gas storage contracts provided increased revenues, as well as greater flexibility for our customers. Throughout the year, we continued to renegotiate and realign our producer contracts. We have increased volumes under our Percent-of-Proceeds contracts to capture benefits from rising commodity prices. We also continue efforts to include conditioning language in our Keep-Whole contracts, which allows us to benefit from widening gas processing spreads while also protecting us from losses. Some 35 percent of our Keep-Whole contracts now have conditioning language. We are comfortable with our contract mix by volume, which is: Fee Based, 48 percent; Percent of Proceeds, 36 percent; and Keep Whole, 16 percent. As recently as 2002, our Keep-Whole contracts had represented 28 percent of our contracts by volume.

• During the year, the Gas Processors Association awarded our Natural Gas Liquids and Gathering and Processing employees with its President's Award for Safety Improvement.

"We have well-positioned assets operated by knowledgeable people who execute our business plan day in and day out. This combination of planning, people and assets created exceptional value in 2005, not only for ONEOK and its share-holders but also for our customers. When you back out the gain from our sale of the Texas gathering and processing assets, Energy Companies' operating income increased 29 percent over the previous year. Our focus is to ensure that all of the assets work together, not just work. And it's to make sure we own the right assets, not just assets. Our acquisition and integration of the natural gas liquids business we acquired at mid-year is a very good example of this. As a result of transactions recently announced with Northern Border Partners, our Gathering and Processing, Pipelines and Storage and Natural Gas Liquids segments will transfer into Northern Border Partners. We will retain Energy Services, our marketing and trading segment, which had a stellar year. On the ground, where performance is measured daily, all of these energy assets will continue to be run by the same excellent people. We will continue working together to profitably optimize and grow our operations while aggressively seeking acquisitions that fit."

"Our opportunity – and our challenge – is to deliver value that customers recognize and appreciate while also ensuring that we are compensated appropriately through our rates."

SAMUEL COMBS III

President,
ONEOK Distribution Companies

DISTRIBUTION

HIGHLIGHTS AND FEATURES

- ONEOK's Distribution Companies recorded operating income of $113.9 million, a 3.3 percent increase over 2004 results. Net margins increased $30.4 million, primarily due to implementation of new rates in Oklahoma. Margin increases, which included additional wholesale transactions in Kansas, were partially offset by a decrease in sales volumes because of warmer than normal weather.
- Oklahoma Natural Gas implemented new rates for its more than 800,000 customers on July 28, marking the first increase in base rates in a decade. It had sought $99.4 million in additional annual revenues; the state's corporation commission approved a $57.5 million increase. We plan to file for future rate increases in a more timely manner to reflect ongoing capital investments. (This rate case and some of its features are discussed in our chairman's letter to shareholders.)
- Kansas Gas Service in 2005 received approval to recover the fuel-related portion of its bad debts; gas costs make up approximately 75 percent of an average customer bill. Also, Kansas Gas Service has requested approval of a mechanism that would reduce regulatory lag time between capital investments and return on those investments. Similar mechanisms are in place in some of our Texas Gas Service jurisdictions. This May, Kansas Gas Service will request a general rate increase. The last increase was implemented in 2003, when a three-year moratorium was established.
- Texas Gas Service in November filed for general rate increases in the Port Arthur/south Jefferson County and north Texas jurisdictions. These requests for $2.4 million and $1.1 million in additional revenues, respectively, will be resolved in 2006.
- Our rate structures in Oklahoma and Kansas contain weather normalization clauses, which help provide stable earnings while also reducing the volatility in the customers' bills during abnormally cold weather. Approximately 80 percent of our business in Texas is insensitive to weather as a result of the front-loaded rate design in those jurisdictions.
- Planned capital expenditures for 2006 are $148.0 million, compared with $143.8 million in 2005.
- Texas Gas Service was first in business customer satisfaction, according to survey results released in February 2006 by a leading consumer research firm.

"Our distribution companies – Oklahoma Natural Gas, Kansas Gas Service and Texas Gas Service – generate significant cash flow and steady earnings while providing reliable gas service to more than two million customers. In 2005 we centralized our management structure to capture additional synergies, standardize processes and promote an integrated strategy. These changes will enable us to work more effectively and deliver greater value to ONEOK's shareholders and customers. We draw upon a skilled and experienced workforce to improve results, first by understanding the needs of our customers and then investing in projects that support growth, improve productivity and reduce expenses. Through system acquisitions and extensions, we have grown our customer base by more than one million accounts over the past eight years. Our opportunity – and our challenge – is to deliver value that customers recognize and appreciate while also ensuring that we are compensated appropriately through our rates."

FINANCE

ONEOK HAS ACHIEVED CONSECUTIVE PROFITABLE EARNINGS EACH YEAR SINCE THE COMPANY WAS RESTRUCTURED IN 1933, DURING THE GREAT DEPRESSION.

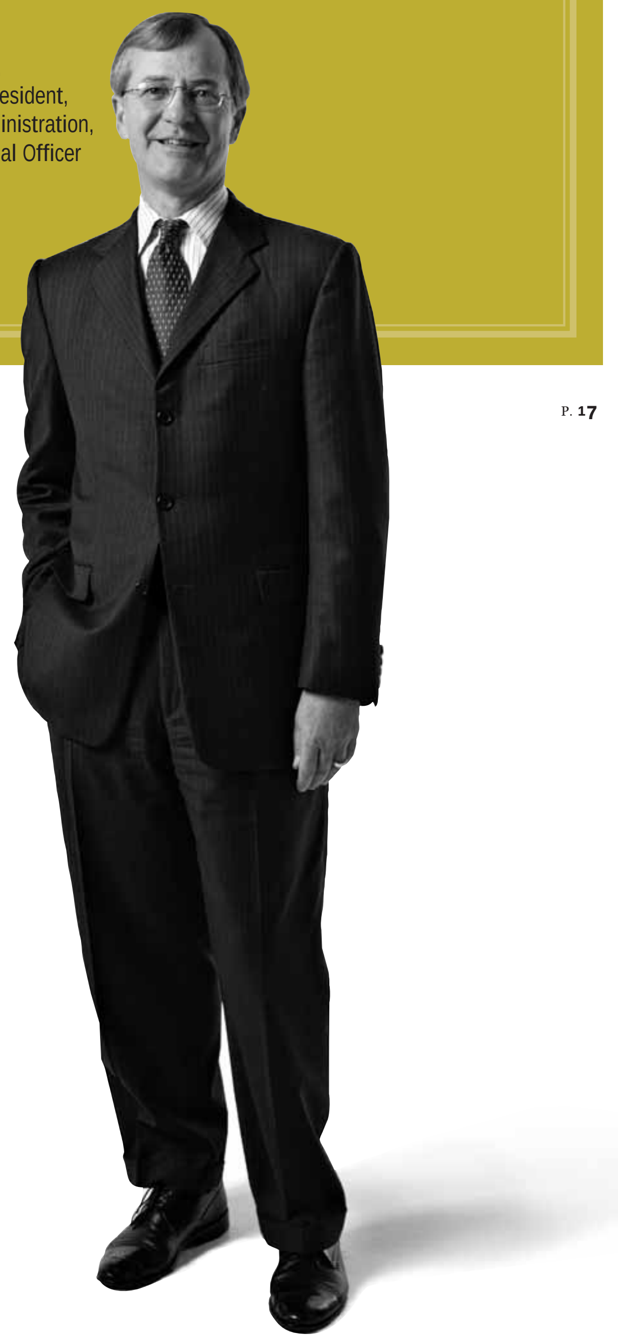
HIGHLIGHTS AND FEATURES

- ONEOK has achieved consecutive profitable earnings each year since the company was restructured in 1933, during the Great Depression.
- We increased the stock dividend by 12 percent in 2005. The dividend has been increased on six occasions since 2002. It was increased by 16 percent in 2003 and 39 percent in 2004. We monitor and adjust the dividend yield to ensure that it continues to provide attractive returns to ONEOK shareholders.
- An $800 million bond offering last summer, made in conjunction with the $1.35 billion acquisition of the natural gas liquids business, was heavily oversubscribed – a strong indication of how positively the ONEOK name and its integrity are recognized in the bond market.
- Free cash flow in 2005 was $159 million.
- Effective January 1, 2006, financial results from Northern Border Partners, one of the nation's largest master limited partnerships, will be consolidated with and reported in ONEOK's financial results. Pending regulatory approval expected by April, ONEOK will own 45.7 percent of Northern Border Partners and 100 percent of the general-partner interest. ONEOK also will receive approximately $1.35 billion in cash, part of which will be used to pay off existing short-term debt and part of which will be kept as cash on hand. Cash on hand is expected to be approximately $680 million after the transaction is completed. ONEOK has access to a $1.2 billion credit facility.
- ONEOK's board of directors in November 2005 authorized the company to repurchase up to an additional 7.5 million shares of common stock, which doubled the number originally authorized early in the year.
- In February 2006, holders of 16.1 million ONEOK equity units turned them in and purchased approximately 19.5 million shares of newly issued ONEOK common stock. We received approximately $402 million in cash and used this to reduce short-term debt. We issued the equity units in 2003 as a financial tool that allowed us to completely end a cumbersome relationship with another company dating to our 1997 acquisition of major natural gas assets in Kansas. The Kansas acquisition served as our launch point to become a premier, diversified energy company.

"Our company is, by design, acquisitive, opportunistic and purposeful. As a result, from time to time we stretch the balance sheet to make acquisitions that meet our strict criteria for growth and long-term value. We also are committed to maintaining a strong, investment-grade credit rating, so we always rebalance the ledger through management of cash flows, sale of assets and other means. After the closing of the transactions with Northern Border Partners, we will be positioned with a strong balance sheet and the ability to make other strategic acquisitions or to repurchase ONEOK stock. It is a great position to be in, particularly when combined with our very strong cash flow and high levels of cash on hand."

“After the closing of the transactions with Northern Border Partners, we will be positioned with a strong balance sheet and the ability to make other strategic acquisitions or to repurchase ONEOK stock. It is a great position to be in...“

JIM KNEALE
Executive Vice President,
Finance and Administration,
and Chief Financial Officer

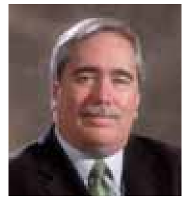


DIRECTORS

William M. Bell
Vice Chairman
BancFirst
Oklahoma City, Oklahoma

James C. Day
Chairman of the Board and
Chief Executive Officer
Noble Corporation
Sugar Land, Texas

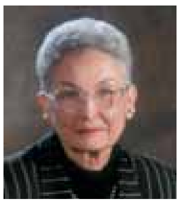
William L. Ford
President
Shawnee Milling Company
Shawnee, Oklahoma



David L. Kyle
Chairman, President and
Chief Executive Officer
ONEOK, Inc.
Tulsa, Oklahoma

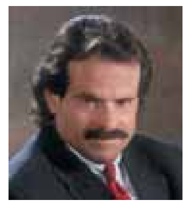
Bert H. Mackie
Vice Chairman
President and Director
Security National Bank
Enid, Oklahoma

Pattye L. Moore
Consultant
Oklahoma City, Oklahoma

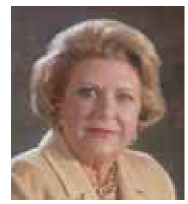


Douglas Ann Newsom, Ph.D.
Professor, Schieffer
School of Journalism
Texas Christian University
Fort Worth, Texas

Gary D. Parker
President
Moffitt, Parker &
Company, Inc.
Muskogee, Oklahoma



Eduardo A. Rodriguez
President
Strategic Communication
Consulting Group
El Paso, Texas



Mollie B. Williford
Chairman
The Williford Companies
Tulsa, Oklahoma

OFFICERS

ONEOK, INC.

David L. Kyle, 53
Chairman of the Board, President and
Chief Executive Officer

James C. Kneale, 54
Executive Vice President – Finance and
Administration and Chief Financial Officer

John A. Gaberino Jr., 64
Senior Vice President and Special
Counsel to the Chairman of the Board

John R. Barker, 58
Senior Vice President and General
Counsel

Curtis L. Dinan, 38
Senior Vice President and Chief
Accounting Officer

Caron A. Lawhorn, 45
Senior Vice President – Financial Services
and Treasurer

ONEOK DISTRIBUTION COMPANIES

Samuel Combs III, 48
President

KANSAS GAS SERVICE COMPANY

Bradley O. Dixon, 52
President

OKLAHOMA NATURAL GAS COMPANY

Phyllis S. Worley, 55
President

TEXAS GAS SERVICE COMPANY

Roger N. Mitchell, 54
President

ONEOK ENERGY COMPANIES

John W. Gibson, 53
President

ONEOK ENERGY SERVICES COMPANY

William S. Maxwell, 45
President

GATHERING AND PROCESSING

Pierce H. Norton II, 46
President

NATURAL GAS LIQUIDS

Terry K. Spencer, 46
President

PIPELINES AND STORAGE

S.W. Walker, 55
President

PIPELINE SERVICES

Stephan R. Guy, 51
President

NORTHERN BORDER PARTNERS, L.P.

William R. Cordes, 57
Chief Executive Officer –
Northern Border Partners, L.P. and
President – Northern Plains
Natural Gas Company

CHAIRMAN EMERITUS

C.C. Ingram
ONEOK, Inc.
Tulsa, Oklahoma

10-K

ONEOK, Inc. FORM 10-K

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

X ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2005.
OR
___ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from __________ to __________.

Commission file number **001-13643**

ONEOK, Inc.

(Exact name of registrant as specified in its charter)

Oklahoma	**73-1520922**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
100 West Fifth Street, Tulsa, OK	**74103**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code **(918) 588-7000**

Securities registered pursuant to Section 12(b) of the Act:

Common stock, par value of $0.01	**New York Stock Exchange**
(Title of Each Class)	(Name of Each Exchange on which Registered)

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes X No__.

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes __ No X.

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes X No __

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Registration S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. __

Indicate by checkmark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one)
Large accelerated filer X Accelerated filer __ Non-accelerated filer __

Indicate by checkmark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes__ No X.

Aggregate market value of registrant's common stock held by non-affiliates based on the closing trade price on June 30, 2005, was $3,233.9 million.

On March 6, 2006, the Company had 117,243,278 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the definitive proxy statement to be delivered to shareholders in connection with the Annual Meeting of Shareholders to be held May 18, 2006, are incorporated by reference in Part III.

ONEOK, Inc.
2005 ANNUAL REPORT ON FORM 10-K

As used in this Annual Report on Form 10-K, the terms "we," "our" or "us" mean ONEOK, Inc., an Oklahoma corporation, and its predecessors and subsidiaries, unless the context indicates otherwise.

PART I.

ITEM 1. BUSINESS

DEFINITIONS

Following are definitions of abbreviations used in this Form 10-K:

Bbl	42 United States (U.S.) gallons, the basic unit for measuring crude oil, natural gas liquids and natural gas condensate
Bbl/d	42 United States (U.S.) gallons, the basic unit for measuring crude oil, natural gas liquids and natural gas condensate per day
MBbls	One thousand barrels
MBbls/d	One thousand barrels per day
MMBbls	One million barrels
Btu	British thermal unit, a measure of the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit
MMBtu	One million British thermal units
MMMBtu/d	One billion British thermal units per day
Mcf	One thousand cubic feet of gas
MMcf	One million cubic feet of gas
MMcf/d	One million cubic feet of gas per day
Bcf	One billion cubic feet of gas
Bcf/d	One billion cubic feet of gas per day

GENERAL

ONEOK, Inc., an Oklahoma corporation, was organized on May 16, 1997. On November 26, 1997, we acquired the natural gas business of Westar Energy, Inc. (Westar), formerly Western Resources, Inc., and merged with ONEOK, Inc., a Delaware corporation organized in 1933. We are the successor to a company founded in 1906 as Oklahoma Natural Gas Company.

We purchase, gather, process, transport, store and distribute natural gas. We extract, fractionate, store, transport, sell and market natural gas liquids (NGLs); and are engaged in natural gas, crude oil, NGLs and electricity marketing, retail natural gas marketing and trading activities. We are the largest natural gas distributor in Oklahoma and Kansas and the third largest natural gas distributor in Texas, providing service as a regulated public utility to wholesale and retail customers. Our largest distribution markets are Oklahoma City and Tulsa, Oklahoma; Kansas City, Wichita, and Topeka, Kansas; and Austin and El Paso, Texas. Our energy services operations provide services to customers in many states. We acquired Northern Plains Natural Gas Company and its wholly owned subsidiary Pan Border Gas Company (collectively, Northern Plains) in November 2004. As a result of this acquisition, we are the majority general partner of Northern Border Partners, one of the largest publicly-traded master limited partnerships. Northern Border Partners acquires, owns and manages pipelines and other midstream energy assets and is a leading transporter of natural gas imported from Canada into the United States.

In December 2005, we sold our natural gas gathering and processing assets located in Texas to a subsidiary of Eagle Rock Energy, Inc.

We completed the sale of our Production segment to TXOK Acquisition, Inc. in September 2005. The financial information related to the properties sold is reflected as a discontinued component in this Annual Report on Form 10-K. All periods presented have been restated to reflect the discontinued component.

In July 2005, we completed the acquisition of the natural gas liquids businesses owned by several affiliates and a subsidiary of Koch Industries, Inc. (Koch). This transaction included Koch Hydrocarbon, LP's entire mid-continent natural gas liquids fractionation business; Koch Pipeline Company, LP's natural gas liquids pipeline distribution systems; Chisholm Pipeline Holdings, Inc., which has a 50 percent ownership interest in Chisholm Pipeline Company; MBFF, LP, which owns an 80 percent interest in a 160,000 barrel per day fractionator at Mont Belvieu, Texas; and Koch Vesco Holdings, LLC, an entity that owns a 10.2 percent interest in Venice Energy Services Company, LLC (VESCO).

DESCRIPTION OF BUSINESS SEGMENTS

We report operations in the following reportable business segments:

- Gathering and Processing

- Natural Gas Liquids
- Pipelines and Storage
- Energy Services
- Distribution
- Other

For financial and statistical information regarding our business units by segment, see Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations. See Note M of Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for a discussion of changes in reportable business segments as well as sales to unaffiliated customers, operating income and total assets by business segment.

Gathering and Processing

Segment Description - Our Gathering and Processing segment is engaged in the gathering and processing of natural gas and fractionation of natural gas liquids (NGLs) primarily in Oklahoma and Kansas. Our operations include the gathering of natural gas production from crude oil and natural gas wells. Through gathering systems, these volumes are aggregated for removal of water vapor, solids and other contaminants and to extract NGLs in order to provide marketable natural gas, commonly referred to as residue gas. When the liquids are separated from the raw natural gas at the processing plants, the liquids are generally in the form of a mixed NGL stream. This stream can then be separated by a distillation process, referred to as fractionation, into marketable product components such as ethane, propane, iso-butane, normal butane and natural gasoline. The component products can then be stored, transported and marketed to a diverse customer base of end-users.

We generally gather and process gas under three types of contracts:

- Keep Whole - Under a keep whole processing contract, we extract NGLs and return to the producer volumes of merchantable natural gas containing the same amount of Btus as the raw natural gas that was delivered to us. We retain the NGLs as our fee for processing. Accordingly, we must purchase and return to the producer sufficient volumes of merchantable natural gas to replace the Btus that were removed as NGLs through the gathering and processing operation, commonly referred to as "shrink." By using this contract type, the producer is kept whole on a Btu basis. This type of contract exposes us to the keep whole spread, or gross processing spread, which is the relative difference in the economic value between NGLs and natural gas on a Btu basis. We typically bear the full cost of the plant fuel consumed in processing under these contracts which usually include a fee-based gathering agreement. The main factors that affect our keep whole margins include:
    - shrink,
    - plant fuel consumed,
    - transportation and fractionation costs incurred on the NGLs,
    - gross processing spread, and
    - the mid-continent natural gas price, crude oil price and the daily average Oil Price Information Service (OPIS) price for our NGL products sold.
- Percent of Proceeds (POP) - Under a POP contract, we retain a percentage of the NGLs and/or a percentage of the natural gas as payment for gathering, compressing and processing the producer's raw natural gas. The producer may take its share of the NGLs and natural gas in kind or receive its share of proceeds from our sale of the commodities. We also have POP contracts that have an associated fee for providing services such as gathering, dehydration, compression and treating. The POP contract exposes us to both natural gas and NGL commodity price risk, but economically aligns us with the producer because we both benefit from higher commodity prices. There are a variety of factors that directly affect our POP margins, including:
    - the percentages of products retained that represent our equity NGL, condensate and natural gas sales volumes,
    - transportation and fractionation rates incurred on the NGLs, and
    - the mid-continent natural gas price, crude oil price and the daily average OPIS price received for our equity products retained.

  Additionally, we purchase natural gas at the wellhead under index-based purchase agreements that we use for operational purposes, such as fuel and shrink, with the excess being sold monthly at index-based prices.
- Fee - Under a fee contract, we are paid a fee for the services provided such as Btus gathered, compressed and/or processed. The wellhead volume and fees received for the services provided are the main components of the margin for this type of contract. The producer may take its NGLs and natural gas in kind or receive its proceeds from our sale of the commodities. This type of contract exposes us to minimal commodity price risk; however, there is still volumetric risk with this contract structure.

Operating income from our Gathering and Processing segment was 49.5 percent, 26.2 percent and 13.1 percent of our consolidated operating income from continuing operations in 2005, 2004 and 2003, respectively. Our Gathering and Processing segment had no single external customer from which it received ten percent or more of consolidated revenues. Intersegment sales accounted for 84 percent, 81 percent and 76 percent of our Gathering and Processing segment's revenues in 2005, 2004 and 2003, respectively.

Market Conditions and Seasonality - Contracts covering approximately 35 percent of the volumes associated with our keep whole contracts allow us to charge conditioning fees for processing, in the event the keep whole spread is negative. This helps mitigate the impact of an unfavorable keep whole spread by effectively converting the keep whole contract to a fee contract during periods of negative keep whole spreads. Our effort to add this conditioning language is a continuing strategy. We also continue our strategy of renegotiating any under-performing gas purchase, gathering and processing contracts.

Additionally, we have the ability to adjust plant operations to take advantage of market conditions. By changing the temperatures and pressures at which the natural gas is processed, we can produce more of the specific commodities that have the most favorable prices or price spread.

During the year, both crude oil and natural gas prices were volatile, with New York Mercantile Exchange (NYMEX) crude oil settlement prices ranging from $45.64 to $66.23 per Bbl and NYMEX natural gas settlement prices ranging from $6.12 to $13.91 per MMBtu.

We are affected by producer drilling activity, which is sensitive to geological success, as well as availability of capital, commodity prices and regulatory control. The mid-continent region is currently experiencing a significant upturn in crude oil and natural gas drilling activity. This resurgence in drilling activity has been driven by increased prices for natural gas and crude oil and by long-term projections of continued demand in the U.S. natural gas market. However, we are exposed to volume risk from a competitive and a production standpoint. We continue to see declines in certain fields that supply our gathering and processing operations, and the possibility exists that volumetric declines may surpass new gas development from future drilling.

Despite significant consolidation in the recent past, the U.S. midstream industry remains relatively fragmented, and we face competition from a variety of companies, including major integrated oil companies, major pipeline companies and their affiliated marketing companies, and national and local natural gas gatherers, processors and marketers. Competition exists for obtaining natural gas supplies for gathering and processing operations. The factors that typically affect our ability to compete are:

- producer drilling activity,
- petrochemical industry's level of capacity utilization and its specific feedstock requirements,
- fees charged under the contract,
- pressures maintained on the gathering systems,
- location of our gathering systems relative to our competitors,
- location of our gathering systems relative to the drilling activity,
- efficiency and reliability of the operations, and
- delivery capabilities that exist in each system and plant location.

We have responded to these industry conditions by making capital investments to improve plant processing flexibility and reduce operating costs, selling assets in non-core operating areas and renegotiating unprofitable contracts. The principal goal of the contract renegotiation effort is to eliminate unprofitable contracts and improve margins, primarily when the keep whole spread is negative.

Some of our products, such as natural gas and propane used for heating, are subject to seasonality, resulting in more demand during the months of November through March. As a result, prices of these products are typically higher during that time period. We are also starting to see an increase in the demand for natural gas in the summer periods as more electric generation is dependent upon natural gas for fuel. Other products, such as ethane, are tied to the petrochemical industry, while iso-butane and natural gasoline are used by the refining industry as blending stocks. As a result, the prices of these products are affected by the economic conditions and demand associated with these various industries.

Government Regulation - The Federal Energy Regulatory Commission (FERC) has traditionally maintained that a processing plant is not a facility for transportation or sale for resale of natural gas in interstate commerce and, therefore, is not subject to jurisdiction under the Natural Gas Act (NGA). Although the FERC has made no specific declaration as to the jurisdictional status of our natural gas processing operations or facilities, our natural gas processing plants are primarily involved in removing NGLs and, therefore, we believe, are exempt from FERC jurisdiction. The NGA also exempts natural gas gathering facilities from the jurisdiction of the FERC. Interstate transmission facilities remain subject to FERC jurisdiction. The FERC has historically distinguished between these two types of facilities on a fact-specific basis. We believe our gathering facilities and operations meet the criteria used by the FERC to determine a non-jurisdictional gathering facility status. We can transport residue gas from our plants to interstate pipelines in accordance with Section 311(a) of the Natural Gas Policy Act (NGPA).

The states of Oklahoma and Kansas also have statutes regulating, in various degrees, the gathering of natural gas in those states. In each state, regulation is applied on a case-by-case basis if a complaint is filed against the gatherer with the appropriate state regulatory agency.

Natural Gas Liquids

Segment Description - Our Natural Gas Liquids segment gathers, stores, fractionates and treats raw NGLs produced from natural gas processing plants located in Oklahoma, Kansas and the Texas panhandle. This segment was formed in July 2005 primarily from our acquisition of the Koch assets. See Note B of Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional information. We connect the NGL production basins in Oklahoma, Kansas and the Texas panhandle with the key NGL market centers in Conway, Kansas and Mont Belvieu, Texas.

Most natural gas produced at the wellhead contains a mixture of NGL components such as ethane, propane, iso-butane, normal butane and natural gasoline. Natural gas processing plants remove the NGLs from the natural gas stream to realize the higher economic value of the NGLs and to meet natural gas pipeline quality specifications, which limit NGLs in the natural gas stream due to liquid and Btu content.

The NGLs that are separated from the natural gas stream at the natural gas processing plants remain in a mixed, raw form until they are gathered, primarily by pipeline, and delivered to our fractionators. A fractionator, by applying heat and pressure, separates each NGL component into marketable products, such as ethane/propane mix, propane, iso-butane, normal butane and natural gasoline (collectively, NGL products). These NGL products are then stored and/or distributed to petrochemical, heating and motor gasoline manufacturers.

Our Natural Gas Liquids segment focuses on increasing the market value of NGL products through the use of our natural gas liquids assets. We are engaged in three primary business activities downstream of our Gathering and Processing segment.

- Exchange Services - We provide gathering, fractionation, transportation, storage and treating of NGLs through term, fee-based exchange contracts. Under a typical fee-based exchange contract, we provide bundled services that include gathering and transporting raw NGLs to our fractionators, separating them into marketable products and redelivering the NGL products to our customers.
- Optimization and Marketing - We use our asset base, portfolio of contracts and market knowledge to capture location price spreads through transactions that optimize the flow of our NGL products between the major market centers in Conway, Kansas and Mont Belvieu, Texas. Optimization activities include redirecting NGL products to their highest value locations. In the mid-continent area, we purchase approximately two-thirds of our customers' raw products on an index pricing basis, less an exchange fee. Although most of our storage is leased to third parties for a fee, we also own and lease storage in the mid-continent and gulf coast areas which provides opportunities to capture seasonal price variances.
- Isomerization - We own an isomerization unit in Conway, Kansas, with a capacity of 9 MBbls/d that converts normal butane to the more valuable iso-butane used by the refining industry to upgrade the octane of motor gasoline.

Operating income from our Natural Gas Liquids segment, which was formed in July 2005 primarily from our acquisition of the Koch assets, was 5.4 percent, 3.3 percent and 1.5 percent of our consolidated operating income from continuing operations in 2005, 2004 and 2003, respectively. Our Natural Gas Liquids segment had no single external customer from which it received ten percent or more of consolidated revenues.

Market Conditions and Seasonality - During the year, natural gas, crude oil and NGL product prices were volatile, with NYMEX crude oil settlement prices ranging from $45.64 to $66.23 per Bbl and the NYMEX natural gas settlement prices ranging from $6.12 to $13.91 per MMBtu.

Similar to our Gathering and Processing segment, our Natural Gas Liquids segment is also affected by producer drilling activity. The mid-continent region is currently experiencing a significant upturn in crude oil and natural gas drilling activity. This resurgence in drilling activity has been driven primarily by increased prices for natural gas and crude oil and by long-term projections of continued demand in the U.S. natural gas market. However, we continue to see production declines in certain fields that supply the gathering and processing facilities that feed our systems and the possibility exists that declines may surpass development from new drilling. The factors that typically affect our ability to compete for NGL supplies are:

- location of natural gas processing plants relative to our gathering pipelines,
- location of our gathering pipelines relative to our competitors,
- location of our fractionation facilities relative to our competitors,
- efficiency, reliability and costs of operations including fuel and power consumption,
- available fractionation, pipeline and storage capacity, and
- delivery capabilities to move NGL products to their highest value locations.

Our natural gas liquids gathering pipelines are affected by operational or market-driven changes in the output of the processing plants to which we are connected. Increases or decreases in gas processing plant output may affect the volume of NGLs shipped through the system as a result of the relative value of natural gas to NGL prices, primarily ethane to natural gas and then composite NGL price to natural gas.

The main factors that affect our margins are:

- transportation and fractionation volumes and associated fees,
- commodity and regional pricing differences, and
- fees charged for storage.

We have acquired assets that are strategically located near our existing assets, making capital investments to improve operational efficiencies and controlling costs. Some of our products, such as propane, which is used for heating, and iso-butane and natural gasoline, used in motor fuel, are subject to seasonality resulting in higher prices during periods of higher demand. Other products, such as ethane, are tied to the petrochemical industry and iso-butane and natural gasoline are used by the refining industry as blending stocks. As a result, the prices of these products are affected by the economic condition and demand associated with these industries.

Government Regulations - Tariff revenues for our proprietary pipelines in both Oklahoma and Kansas are not regulated by the FERC or the states' respective corporation commissions.

Our fractionation facilities are operated under the regulatory framework and oversight of various governmental agencies. These primarily include the U.S. Environmental Protection Agency (EPA) and its state counterparts, as well as the Occupational Safety and Health Administration (OSHA). We have developed systems to identify, control, and manage compliance risks and obligations, including environmental, health and safety management systems.

Our gathering pipelines are operated under the guidance and oversight of various governmental agencies. Besides programs mandated by OSHA, EPA and various state environmental agencies, the U.S. Department of Transportation's Office of Pipeline Safety (OPS) as well as the Oklahoma Corporation Commission (OCC), Kansas Corporation Commission (KCC) and the Texas Railroad Commission (RRC), have each established a regulatory framework focused on asset integrity, safety and environmental protection.

Pipelines and Storage

Segment Description - Our Pipelines and Storage segment, formerly Transportation and Storage, operates our intrastate natural gas transmission pipelines, natural gas storage, regulated natural gas liquids gathering and distribution pipelines, and non-processable natural gas gathering facilities. We also provide interstate natural gas transportation and storage service under Section 311(a) of the NGPA.

In Oklahoma, we have access to the major natural gas producing areas, allowing for natural gas and natural gas liquids to be moved throughout the state. We have access to the major natural gas producing area in south central Kansas. In Texas, we are connected to the major natural gas producing areas in the Texas panhandle and the Permian Basin, providing for natural gas to be moved to the Waha Hub, where other pipelines may be accessed for transportation east to the Houston Ship Channel market and west to the California market. Our natural gas liquids gathering connections provide for raw NGLs gathered in Oklahoma, Kansas and the Texas panhandle to be delivered to our fractionation facilities in these states and to our natural gas liquids distribution pipelines which allows access to the two main NGL market centers in Conway, Kansas and Mont Belvieu, Texas.

We own or reserve storage capacity in five underground natural gas storage facilities in Oklahoma, three underground natural gas storage facilities in Kansas and three underground natural gas storage facilities in Texas.

Through our acquisition of the Koch natural gas liquids assets in July 2005, we operate approximately 2,500 miles of FERC regulated natural gas liquids gathering and distribution pipelines in Oklahoma, Kansas and Texas. Our natural gas liquids gathering pipelines deliver raw NGLs gathered from natural gas processing plants located in these states to fractionation facilities in Medford, Oklahoma, Hutchinson and Conway, Kansas, and Mont Belvieu, Texas. Our natural gas liquids distribution pipelines move products from Oklahoma and Kansas to the market centers of Conway, Kansas and Mont Belvieu, Texas.

The majority of our Pipelines and Storage segment's revenues are derived from services provided to affiliates. Operating income from our Pipelines and Storage segment was 10.6 percent, 13.5 percent and 11.9 percent of our consolidated operating income from continuing operations in 2005, 2004 and 2003, respectively. Our Pipelines and Storage segment had no single external customer from which it received ten percent or more of consolidated revenues. Intersegment sales accounted for 69 percent, 61 percent and 57 percent of our Pipelines and Storage segment's revenues in 2005, 2004 and 2003, respectively.

Market Conditions and Seasonality - Our natural gas assets primarily serve local distribution companies (LDCs), large industrial companies, municipalities, irrigation customers, power generation facilities and marketing companies. Our natural gas liquids gathering assets provide gathering services for shippers from processing plants in Oklahoma, Kansas and Texas to our fractionation facilities. Our natural gas liquids distribution pipelines provide shippers with access to the key natural gas liquids markets located in Conway, Kansas and Mont Belvieu, Texas. Our natural gas and natural gas liquids pipelines compete directly with other intrastate and interstate pipeline companies. Additionally, we compete directly with other storage facilities. Competition for natural gas transportation services continues to increase as the FERC and state regulatory bodies continue to encourage more competition in the natural gas markets. Factors that affect competition for both natural gas and NGL services are location, market access, natural gas and NGL prices, fees for services and quality of services provided. We believe that our pipelines and natural gas storage assets enable us to compete effectively.

Our business is affected by the economy, natural gas and NGL price volatility, and weather. The strength of the economy has a direct relationship on manufacturing and industrial companies and their resulting demand for natural gas and NGL products. Volatility in the natural gas market also impacts our customers' decisions relating to injection and withdrawal of natural gas in storage. In addition, our natural gas liquids gathering pipelines are affected by operational or market driven changes in the output of the gas processing plants to which we are connected. Gas processing plant output may increase or decrease affecting the volume of NGLs shipped through the system as a result of the relative value of natural gas to NGL prices, primarily ethane to natural gas and composite NGL price to natural gas. In addition, volume delivered through the system may increase or decrease as a result of the relative NGL price between the mid-continent and gulf coast regions. Natural gas transportation throughput fluctuates due to rainfall that impacts irrigation demand, hot temperatures that affect power generation demand and cold temperatures that affect heating demand.

Government Regulation - Our natural gas transportation assets in Oklahoma, Kansas and Texas are regulated by the OCC, KCC and RRC, respectively. We have flexibility in establishing natural gas transportation rates with customers. However, there is a maximum rate that we can charge our customers in Oklahoma and Kansas. Our natural gas liquids gathering and distribution pipelines in Oklahoma, Kansas and Texas are interstate pipelines regulated by the FERC and the OPS. We transport raw NGLs and NGL products pursuant to filed tariffs.

Energy Services

Segment Description - Our Energy Services segment's primary focus is to create value for our customers by delivering physical products and risk management services through our network of contracted gas supply, transportation and storage capacity. These services include meeting our customers' baseload, swing and peaking natural gas commodity requirements on a year-round basis. To provide these bundled services, we lease storage and transportation capacity. Our total storage capacity under lease is 86 Bcf, with maximum withdrawal capability of 2.3 Bcf/d and maximum injection capability of 1.6 Bcf/d. Our current transportation capacity is 1.9 Bcf/d. The contracted storage and transportation capacity connects the major supply and demand centers throughout the United States and into Canada. With these contracted assets, our business strategies include identifying, developing and delivering specialized services and products for premium value to our customers, which are primarily LDCs, electric utilities, and commercial and industrial end users. Also, our storage and transportation capacity allows us opportunities to optimize these positions through our application of market knowledge and risk management skills.

We actively manage the commodity price and volatility risk assumed from providing energy risk management services to our customers by executing derivative instruments in accordance with the parameters established in our marketing and trading policy. The derivative instruments consist of over-the-counter financially settled transactions such as swaps, options and NYMEX futures.

Our working capital requirements related to our inventory in storage were as high as $670.9 million during 2005, but had decreased to $505.0 million at December 31, 2005. In addition, our margin requirements with counterparties can result in increased working capital requirements. During 2005, our margin requirements ranged from $58.7 million to $312.4 million.

Operating income from our Energy Services segment was 20.7 percent, 31.4 percent and 45.5 percent of our consolidated operating income from continuing operations in 2005, 2004 and 2003, respectively. In 2004, our Energy Services segment had one customer, BP, PLC and affiliates, from which it received $664.4 million, or approximately 11 percent, of consolidated revenues. Our Energy Services segment had no single external customer from which it received ten percent or more of consolidated revenues in 2005 or 2003.

At the beginning of the third quarter of 2004, we completed a reorganization of our Energy Services segment and renewed our focus on our physical marketing and storage business. We separated the management and operations of our wholesale marketing, retail marketing and financial trading activities and began accounting separately for the different types of revenue earned from these activities. Prior to the third quarter of 2004, we managed our Energy Services segment on an integrated basis and presented all energy trading activity on a net basis in our Consolidated Statements of Income.

Market Conditions and Seasonality - In response to a very competitive marketing environment resulting from deregulation of the retail natural gas markets, our strategy is to concentrate our efforts on providing reliable service during peak demand periods and capture opportunities created by short-term pricing volatility through our leased storage and transportation assets. We focus on building and strengthening supplier and customer relationships to execute our strategy.

Due to seasonality of supply and demand balances, earnings may be higher during the winter months than the summer months. Our Energy Services segment’s margins are subject to fluctuations during the year primarily due to the impact certain seasonal factors have on sales volumes and the price of natural gas and crude oil. Natural gas sales volumes are typically higher in the winter heating months than in the summer months, reflecting increased demand due to greater heating requirements and, typically, higher natural gas prices that occur during the winter heating months.

Distribution

Segment Description - Our Distribution segment provides natural gas distribution services to over two million customers in Oklahoma, Kansas and Texas through Oklahoma Natural Gas, Kansas Gas Service and Texas Gas Service, respectively. We serve residential, commercial, industrial and transportation customers in all three states. In addition, our distribution services in Oklahoma and Kansas serve wholesale customers and Texas serves public authority customers.

Our operating results are primarily affected by the number of customers, usage and the ability to establish delivery rates that provide an authorized rate of return on our investment and recovery of our cost of service. Natural gas costs are passed through to our customers based on the actual cost of gas purchased by the respective distribution companies. Substantial fluctuations in natural gas sales can occur from year to year without significantly impacting our gross margin, since the fluctuations in natural gas costs affect natural gas sales and cost of gas by an equivalent amount. Natural gas sales to residential and commercial customers are seasonal, as a substantial portion of natural gas is used principally for heating. Accordingly, the volume of natural gas sales is consistently higher during the heating season (November through March) than in other months of the year.

Operating income from the Distribution segment was 14.3 percent, 24.8 percent and 27.5 percent of the consolidated operating income from continuing operations in 2005, 2004 and 2003, respectively. The decline in our Distribution segment’s operating income as a percent of consolidated operating income is primarily due to the sale of our natural gas gathering and processing assets located in Texas, which resulted in a gain in our consolidated operating income. Our Distribution segment had no single external customer from which it received ten percent or more of consolidated revenues.

Natural Gas Supply - The majority of our distribution segment’s natural gas supply is provided under contracts from a number of suppliers. These contracts are awarded through a competitive bid process. The remainder of our distribution segment’s natural gas supply is purchased from a combination of direct wellhead production, natural gas processing plants, natural gas marketers and production companies.

There is an adequate supply of natural gas available to our utility systems, and we do not anticipate problems with securing additional natural gas supply as needed for our customers. However, if supply shortages occur, Oklahoma Natural Gas’ rate schedule "Order of Curtailment" and Kansas Gas Service’s rate order "Priority of Service" provide for first reducing or totally discontinuing gas service to large industrial users and then requesting that residential and commercial customers reduce their gas requirements to an amount essential for public health and safety. Texas Gas Service’s gas transportation contracts with interruption provisions require large volume users to purchase their natural gas with the understanding that they may be forced to shut down or switch to alternate sources of energy at times when the gas is needed for higher priority customers. In addition, during times of special supply problems, curtailments of deliveries to customers with firm contracts may be made in accordance with guidelines established by appropriate federal, state and local regulatory agencies.

Market Conditions and Seasonality - Oklahoma Natural Gas, Kansas Gas Service and Texas Gas Service distribute natural gas as public utilities to approximately 87 percent, 71 percent and 13 percent of the distribution markets for Oklahoma, Kansas and Texas, respectively. Natural gas sold to residential and commercial customers, which is used primarily for heating and cooking, accounts for approximately 76 and 22 percent of natural gas sales, respectively, in Oklahoma, 58 and 16 percent of natural gas sales, respectively, in Kansas, and 66 and 26 percent of natural gas sales, respectively, in Texas.

A franchise, although nonexclusive, is a utility's right to use the municipal streets, alleys, and other public ways for a defined period of time in exchange for a fee. Oklahoma Natural Gas, Kansas Gas Service and Texas Gas Service hold franchises in 39, 279 and 82 municipalities, respectively. In management's opinion, our franchises contain no unduly burdensome restrictions and are sufficient for the transaction of business in the manner in which it is now conducted.

Under our transportation tariffs, qualifying industrial and commercial customers are able to purchase natural gas from the supplier of their choice and have it transported for a fee by Oklahoma Natural Gas, Kansas Gas Service or Texas Gas Service. Because of increased competition for the transportation of natural gas to commercial and industrial customers, some of these customers may be lost to affiliated or unaffiliated transporters. If our Pipelines and Storage segment gained some of this business, it would result in a shift of some revenues from our Distribution segment to our Pipelines and Storage segment.

The natural gas industry is expected to remain highly competitive, resulting from initiatives being pursued by the industry and regulatory agencies that allow industrial and commercial customers increased options for energy supplies and service. We believe that we must maintain a competitive advantage in order to retain our customers and, accordingly, we focus on providing reliable, efficient service and reducing costs.

The Distribution segment is subject to competition from other pipelines for our existing industrial load. Oklahoma Natural Gas, Kansas Gas Service and Texas Gas Service compete for service to the large industrial and commercial customers and competition continues to lower rates. A portion of Oklahoma Natural Gas' and Kansas Gas Service's transportation services are at negotiated rates that are generally below the approved transportation tariff rates. Increased competition potentially could lower these rates. In the service area for Texas Gas Service, reduced rate transportation service is negotiated only when a competitive pipeline is in proximity to bypass Texas Gas Service or another energy option is available. Any negotiated transportation service contract is filed under a separate, confidential tariff at the RRC. Industrial and transportation sales volumes tend to remain relatively constant throughout the year.

Natural gas sales to residential and commercial customers are seasonal, as a substantial portion of natural gas is used principally for heating. Accordingly, the volume of natural gas sales is consistently higher during the heating season (November through March) than in other months of the year. Tariff rates for Oklahoma Natural Gas and Kansas Gas Service include a temperature normalization adjustment clause during the heating season, which mitigates the effect of fluctuations in weather. The recently authorized rate structure for Oklahoma Natural Gas includes billing options for all gas sales customers. Under this new rate structure, certain high volume customers will pay a higher monthly service charge and a lower per dekatherm delivery charge, while lower usage customers will pay a lower monthly service charge coupled with a higher per dekatherm delivery charge. Customers can elect to change billing options to ensure that they are billed under the alternative that best fits their individual usage, but they must remain on the selected option for a full year after the change is made. Additionally, with prior KCC approval, Kansas Gas Service has a natural gas hedging program in place to reduce volatility in the natural gas price paid by consumers. The costs of this program are borne by the Kansas Gas Service customers. Approximately 84 percent of Texas Gas Service's revenues are protected from abnormal weather due to a higher customer charge or weather normalization adjustment clauses. Texas Gas Service's weather normalization adjustment clause applies to 19 Texas towns and cities, including Austin and Galveston, to stabilize earnings and neutralize the impact of unusual weather on customers. A higher customer charge is included in the authorized rate design for the cities of El Paso and Port Arthur to protect customers from abnormal weather.

Government Regulation - Rates charged for natural gas services are established by the OCC for Oklahoma Natural Gas and by the KCC for Kansas Gas Service. Texas Gas Service is subject to regulatory oversight by the various municipalities that it serves, which have primary jurisdiction in their respective areas. Rates in areas adjacent to the various municipalities and appellate matters are subject to regulatory oversight by the RRC. Natural gas purchase costs are included in the Purchased Gas Adjustment (PGA) clause rate that is billed to customers. Our distribution companies do not make a profit on the cost of gas. Other changes in costs must be recovered through periodic rate adjustments approved by the OCC, KCC, RRC and various municipalities in Texas. See pages 42-43 for a detailed description of our various regulatory initiatives.

Oklahoma Natural Gas has settled all known claims arising out of long-term gas supply contracts containing "take-or-pay" provisions that purport to require us to pay for volumes of natural gas contracted for but not taken. The OCC has authorized recovery of the accumulated settlement costs over a 20-year period expiring in 2014, or approximately $7.0 million annually, through a combination of a surcharge from customers, revenue from transportation under Section 311(a) of the NGPA and other intrastate transportation revenues. There are no significant potential claims or cases pending against us under "take-or-pay" contracts.

Other

Segment Description - The primary companies in our Other segment include ONEOK Leasing Company, ONEOK Parking Company, and Northern Plains, which owns a 1.65 percent general partner interest and a 1.08 percent limited partner interest in Northern Border Partners.

Through ONEOK Leasing Company and ONEOK Parking Company, we own a parking garage and lease an office building (ONEOK Plaza) in downtown Tulsa, Oklahoma, where our headquarters are located. ONEOK Leasing Company leases excess office space to others and operates our headquarters office building. ONEOK Parking Company owns and operates a parking garage adjacent to our headquarters.

Northern Plains was acquired in November 2004 and we account for our 2.73 percent interest in Northern Border Partners following the equity method. Effective January 1, 2006, we were required to consolidate Northern Border Partners in accordance with Emerging Issues Task Force (EITF) Issue No. 04-5, “Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights” (EITF 04-5). See Impact of New Accounting Standards in Item 7, Management’s Discussion and Analysis of Financial Condition and Results of Operation for additional information.

Our Other segment had no single external customer from which it received ten percent or more of consolidated revenues.

ENVIRONMENTAL MATTERS

We own or retain legal responsibility for the environmental conditions at 12 former manufactured gas sites in Kansas. These sites contain potentially harmful materials that are subject to control or remediation under various environmental laws and regulations. A consent agreement with the Kansas Department of Health and Environment (KDHE) presently governs all work at these sites. The terms of the consent agreement allow us to investigate these sites and set remediation activities based upon the results of the investigations and risk analysis. We have commenced active remediation on eight sites, with regulatory closure achieved at two of these locations, and have begun assessments at the four remaining sites. The site situations are not similar, and we have no previous experience with similar remediation efforts. We have completed some analysis of the four remaining sites, but are unable to accurately estimate individual or aggregate costs that may be required to satisfy our remedial obligations.

Our preliminary review of similar cleanup efforts at former manufactured gas sites reveals that costs can range from $100,000 to $10 million per site. These estimates do not consider potential insurance recoveries, recoveries through rates or from unaffiliated parties, to which we may be entitled. At this time, we have not recorded any amounts for potential insurance recoveries or recoveries from unaffiliated parties, and we are not recovering any environmental amounts in rates. Total costs to remediate the two sites, which have achieved regulatory closure, was approximately $700,000. Total remedial costs for each of the remaining sites are expected to exceed $500,000 per site, but there is no assurance that costs to investigate and remediate the remaining sites will not be significantly higher. As more information related to the site investigations and remediation activities becomes available, and to the extent such amounts are expected to exceed our current estimates, additional expenses could be recorded. Such amounts could be material to our results of operations and cash flows depending on the remediation done and number of years over which the remediation is completed.

Our expenditures for environmental evaluation and remediation to date have not been significant in relation to the results of operations and there were no material effects upon earnings during 2005 related to compliance with environmental regulations.

EMPLOYEES

We employed 4,558 people at February 28, 2006. At February 28, 2006, Kansas Gas Service employed 782 people who were subject to collective bargaining contracts, and we had no other union employees. The following table sets forth our contracts with unions at February 28, 2006.

Union	Employees	Contract Expires
United Steelworkers of America	422	June 30, 2009
International Union of Operating Engineers	14	June 30, 2009
Gas Workers Metal Trades of the United Association of Journeyman and Apprentices of the Plumbing and Pipefitting Industry of the United States and Canada	9	June 30, 2009
International Brotherhood of Electrical Workers	337	June 30, 2006

Currently, we have no ongoing labor negotiations, and there are no other unions representing our employees.

EXECUTIVE OFFICERS

All executive officers are elected at the annual meeting of our Board of Directors and serve for a period of one year or until successors are duly elected. Our executive officers listed below include the officers who have been designated by our Board of Directors as our Section 16 executive officers.

Name and Position	Age		Business Experience in Past Five Years
David L. Kyle	53	2000 to present	Chairman of the Board of Directors, President and Chief Executive Officer
Chairman of the Board of		1997 to 2000	President and Chief Operating Officer
Directors, President and		1995 to present	Member of the Board of Directors
Chief Executive Officer			
Jim Kneale	54	2004 to present	Executive Vice President - Finance and Administration and Chief Financial Officer
Executive Vice President-		2001 to 2004	Senior Vice President, Treasurer and Chief Financial Officer
Finance and Administration		1999 to 2000	Vice President, Treasurer and Chief Financial Officer
and Chief Financial Officer			
John R. Barker	58	2004 to present	Senior Vice President, General Counsel and Assistant Secretary
Senior Vice President, General		1994 to 2004	Stockholder, President and Director, Gable & Gotwals
Counsel and Assistant Secretary			
Curtis L. Dinan	38	2004 to present	Senior Vice President and Chief Accounting Officer
Senior Vice President and		2004 to 2004	Vice President and Chief Accounting Officer
Chief Accounting Officer		2002 to 2004	Assurance and Business Advisory Partner, Grant Thornton, LLP
		2000 to 2002	Assurance and Business Advisory Partner, Arthur Andersen, LLP; Assurance and Business Advisory Senior Manager, Arthur Andersen, LLP
John A. Gaberino, Jr.	64	2004 to present	Senior Vice President and Special Counsel to the Chairman of the Board
Senior Vice President and		1998 to 2004	Senior Vice President and General Counsel
Special Counsel to the		2001 to 2003	Corporate Secretary
Chairman of the Board			
William R. Cordes	57	2000 to present	Chief Executive Officer - Northern Border Partners, LP/ President - Northern Plains Natural Gas Company
Chief Executive Officer, Northern		1993 to 2000	President, Northern Natural Gas Company
Border Partners, LP and President,			
Northern Plains Natural Gas Company			
Samuel Combs, III	48	2005 to present	President, ONEOK Distribution Companies
President - ONEOK		2001 to 2005	President, Oklahoma Natural Gas Company
Distribution Companies		1999 to 2001	Vice President - Western Region, Oklahoma Natural Gas Company
John W. Gibson	53	2005 to present	President, ONEOK Energy Companies
President - ONEOK		2000 to 2005	President, Energy
Energy Companies (a)		1995 to 2000	Executive Vice President, Koch Energy, Inc.; President, Koch Midstream Services; President, Koch Gateway Pipeline Company

(a) ONEOK Energy Companies include our Gathering and Processing, Natural Gas Liquids, Pipelines and Storage, and Energy Services segments.

No family relationships exist between any of the executive officers, nor is there any arrangement or understanding between any executive officer and any other person pursuant to which the officer was selected.

AVAILABLE INFORMATION

You can access financial and other information at our website at www.oneok.com. We make available, free of charge, copies of our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, amendments to those reports filed or furnished to the SEC pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, and reports of holdings of our securities filed by our officers and directors under Section 16 of the Securities Exchange Act of 1934 as soon as reasonably practicable after filing such material electronically or otherwise furnishing it to the SEC. Copies of our Code of Business Conduct, Corporate Governance Guidelines, Director Independence Guidelines and Board of Directors committee charters, including the charters of our audit, executive, executive compensation and corporate governance committees, are also available on our website, and we will make available, free of charge, copies of these documents upon request.

ITEM 1A. RISK FACTORS

Our investors should consider the following risks that could affect us and our business. Although we have tried to discuss key factors, please be aware that other risks may prove to be important in the future. New risks may emerge at any time and we cannot predict such risks or estimate the extent to which they may affect our financial performance. Investors should carefully consider the following discussion of risks and the other information included or incorporated by reference in this Annual Report on Form 10-K, including Forward-Looking Information, which is included in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation.

Our nonregulated businesses are riskier than our regulated businesses.

Our nonregulated operations have a higher level of risk than our regulated operations, which include our utility and natural gas transportation businesses. We expect to continue investing in natural gas projects and other related projects, some or all of which may involve nonregulated businesses or assets. These projects could involve risks associated with operational factors, such as competition and dependence on certain suppliers and customers, and financial, economic and political factors, such as rapid and significant changes in prices of hydrocarbons and energy, the cost and availability of capital and counterparty risk, including the inability of a counterparty, customer or supplier to fulfill a contractual obligation.

Our businesses are subject to market and credit risks.

We are exposed to market and credit risks in all of our operations. To minimize the risk of commodity price fluctuations, we periodically enter into derivative transactions to hedge anticipated purchases and sales of natural gas, NGLs, crude oil, fuel requirements and firm transportation commitments. Interest rate swaps are also used to manage interest rate risk. However, financial derivative instrument contracts do not eliminate the risks. Specifically, such risks include commodity price changes, market supply shortages, interest rate changes and counterparty default. The impact of these variables could result in our inability to fulfill contractual obligations, significantly higher energy or fuel costs relative to corresponding sales contracts, or increased interest expense.

Increased competition could have a significant adverse financial impact on us.

The natural gas industry is expected to remain highly competitive, resulting from deregulation and other initiatives being pursued by the industry and regulatory agencies that allow customers increased options for energy supplies and service. The demand for natural gas is primarily a function of commodity prices, including prices for alternative energy sources, customer usage rates, weather, economic conditions and service costs. Our ability to compete also depends on a number of other factors, including competition from other pipelines for our existing load, the efficiency, quality and reliability of the services we provide, and competition for throughput for our gathering systems and processing plants.

In the future, we may face additional competition from new entrants to the energy industry as a result of the Energy Policy Act of 2005. This comprehensive legislation signed into law by President Bush in August 2005 will substantially affect the regulation of energy companies. Among the important changes to be implemented as a result of this act is the repeal of the Public Utility Holding Company Act of 1935 (PUHCA), which is effective in February 2006. PUHCA imposed a number of restrictions, including restrictions on the structure of companies involved in the retail distribution of natural gas. As a result of the repeal of PUHCA, new competitors may enter the industry.

We cannot predict when we will be subject to other changes in legislation or regulation, nor can we predict the impact of these changes on our financial position, results of operations or cash flows. Although we believe our businesses are positioned to compete effectively in the energy market, there are no assurances that this will be true in the future.

We may not be able to successfully make additional strategic acquisitions or integrate businesses we acquire into our operations.

Our ability to successfully make strategic acquisitions and investments will depend on: (1) the extent to which acquisitions and investment opportunities become available; (2) our success in bidding for the opportunities that do become available; (3) regulatory approval, if required, of the acquisitions on favorable terms; and (4) our access to capital, including our ability to use our equity in acquisitions or investments, and the terms upon which we obtain capital. If we are unable to make strategic investments and acquisitions, we may be unable to grow. If we are unable to successfully integrate new businesses into our operations, we could experience increased costs and losses on our investments.

Any reduction in our credit ratings could materially and adversely affect our business, financial condition, liquidity and results of operations.

Our senior unsecured debt has been assigned a rating by Moody's Investors Service, Inc. (Moody's) of "Baa2" (Stable) and by Standard & Poor's Ratings Group (S&P) of "BBB" (CreditWatch with negative implications). We will seek to maintain an investment grade rating through prudent capital management and financing structures. However, we cannot provide assurance that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant. Specifically, if S&P or Moody's were to downgrade our long-term rating, particularly below investment grade, our borrowing costs would increase, which would adversely affect our financial results, and our potential pool of investors and funding sources could decrease. Further, if our short-term ratings were to fall below A-2 (capacity to meet its financial commitment on the obligation is satisfactory) or P-2 (strong ability to repay short-term debt obligations), the current ratings assigned by S&P and Moody's, respectively, it could significantly limit our access to the commercial paper market. Any such downgrade of our long- or short-term ratings could increase our cost of capital and reduce the availability of capital and, thus, have a material adverse effect on our business, financial condition, liquidity and results of operations. Ratings from credit agencies are not recommendations to buy, sell or hold our securities. Each rating should be evaluated independently of any other rating.

We are subject to comprehensive energy regulation by governmental agencies and the recovery of our costs is dependent on regulatory action.

We are subject to comprehensive regulation by several federal, state and municipal utility regulatory agencies, which significantly influences our operating environment and our ability to recover our costs from utility customers. The utility regulatory authorities in Oklahoma, Kansas and Texas regulate many aspects of our utility operations, including customer service and the rates that we can charge customers. Federal, state and local agencies also have jurisdiction over many of our other activities, including regulation by the FERC of our storage and interstate pipeline assets. The profitability of our regulated operations is dependent on our ability to pass costs related to providing energy and other commodities through to our customers. The current regulatory environment applicable to our regulated businesses could impair our ability to recover costs historically absorbed by our customers.

On October 4, 2005, the OCC unanimously approved an annual rate increase of $57.5 million for Oklahoma Natural Gas. Kansas Gas Service began operating under a new rate schedule effective September 22, 2003. As part of the order issued by the KCC, Kansas Gas Service cannot file a new rate case before May 15, 2006.

On November 23, 2005, Texas Gas Service filed requests for rate increases in its Port Arthur and north Texas services areas for $2.4 million and $1.1 million, respectively. The municipalities have suspended the proposed rates for 90 days in order to conduct further review of the filings. Texas Gas Service also has an appeal pending in the court of appeals from the RRC's 2004 order authorizing an annual revenue increase of approximately $0.9 million in the cities of Grove, Port Neches and Nederland, Texas.

We are unable to predict the impact that the future regulatory activities of these agencies will have on our operating results. Changes in regulations or the imposition of additional regulations could have an adverse impact on our business, financial condition and results of operations.

We are subject to environmental regulations that could be difficult and costly to comply with.

We are subject to multiple environmental laws and regulations affecting many aspects of present and future operations, including air emissions, water quality, wastewater discharges, solid wastes and hazardous material and substance management. These laws and regulations generally require us to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals. Failure to comply with these laws, regulations, permits and licenses may expose us to fines, penalties and/or interruptions in our operations that could be material to the results of operations. If an accidental leak or spill of hazardous materials occurs from our lines or facilities in the process of transporting natural gas or NGLs or at any facility that we own, operate or otherwise use, we could be held jointly and severally liable for all resulting liabilities, including investigation and cleanup costs, which could materially affect our results of operations and cash flow. In addition, emission controls required under the Federal Clean Air Act and other similar federal and state laws could require unexpected capital expenditures at our facilities. We cannot provide assurance that existing environmental regulations will not be revised or that new regulations will not be adopted or become applicable to us. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have a material adverse effect on our business, financial condition and results of operations.

We own or retain legal responsibility for the environmental conditions at 12 former manufactured gas sites in Kansas. These sites contain potentially harmful materials that are subject to control or remediation under various environmental laws and regulations. A consent agreement with the KDHE presently governs all remediation work at these sites. The terms of the consent agreement allow us to investigate these sites and set remediation activities based upon the results of the investigations and risk analysis. We have commenced active remediation on eight sites, with regulatory closure achieved at two of these locations, and have begun assessments at the four remaining sites. The site situations are not similar, and we have no previous experience with similar remediation efforts. We have completed some analysis of the four remaining sites, but are unable to accurately estimate individual or aggregate costs that may be required to satisfy our remedial obligations.

Our preliminary review of similar cleanup efforts at former manufactured gas sites reveals that costs can range from $100,000 to $10 million per site. These estimates do not consider potential insurance recoveries, recoveries through rates or from unaffiliated parties, to which we may be entitled. At this time, we have not recorded any amounts for potential insurance recoveries or recoveries from unaffiliated parties, and we are not recovering any environmental amounts in rates. Total costs to remediate the two sites, which have achieved regulatory closure, were approximately $700,000. Total remedial costs for each of the remaining sites are expected to exceed $500,000 per site, but there is no assurance that costs to investigate and remediate the remaining sites will not be significantly higher. As more information related to the site investigations and remediation activities becomes available, and to the extent such amounts are expected to exceed our current estimates, additional expenses could be recorded. Such amounts could be material to our results of operations and cash flows depending on the remediation done and number of years over which the remediation is completed.

Our expenditures for environmental evaluation and remediation to date have not been significant in relation to our results of operations and there were no material effects upon earnings during 2005 related to compliance with environmental regulations.

We are subject to risks that could limit our access to capital, thereby increasing our costs and adversely affecting our results of operations.

We have grown rapidly in the last several years as a result of acquisitions. Further acquisitions may require additional external capital. If we are not able to access capital at competitive rates, our strategy of enhancing the earnings potential of our existing assets, including through acquisitions of complementary assets or businesses, will be adversely affected. A number of factors could adversely affect our ability to access capital, including: (1) general economic conditions; (2) capital market conditions; (3) market prices for natural gas, NGLs and other hydrocarbons; (4) the overall health of the energy and related industries; (5) our ability to maintain our investment-grade credit ratings; and (6) our capital structure. Much of our business is capital intensive, and achievement of our long-term growth targets is dependent, at least in part, upon our ability to access capital at rates and on terms we determine to be attractive. If our ability to access capital becomes significantly constrained, our interest costs will likely increase and our financial condition and future results of operations could be significantly harmed.

Our business could be adversely affected by strikes or work stoppages by our unionized employees.

As of February 28, 2006, approximately 782 of our 4,558 employees were represented by labor unions under collective bargaining agreements. We are involved periodically in discussions with labor unions representing some of our employees to negotiate or renegotiate labor agreements. We cannot predict the results of these negotiations, including whether any failure to reach new agreements will have a negative effect on our business, financial condition and results of operations or whether we will be able to reach any agreement with the unions. Any failure to reach agreement on new labor contracts might result in a work stoppage. Any future work stoppage could, depending on the operations and the length of the work stoppage, have a material adverse effect on our business, financial condition and results of operations.

We do not fully hedge against price changes in commodities. This could result in decreased revenues and increased costs, thereby resulting in lower margins and adversely affecting our results of operations.

Our nonregulated businesses are exposed to market risk and the impact of market price fluctuations of natural gas, NGLs, crude oil and power prices. Market risk refers to the risk of loss in cash flows and future earnings arising from adverse changes in commodity energy prices. Our primary exposure arises from fixed price purchase or sale agreements that extend for periods of up to five years, natural gas in storage utilized by our Energy Services segment, NGLs in storage utilized by our Natural Gas Liquids segment and the difference between natural gas and NGL prices with respect to our keep whole processing agreements. To a lesser extent, we are exposed to the risk of changing prices or the cost of transportation resulting from purchasing natural gas or NGLs at one location and selling it at another (referred to as basis risk). To minimize the risk from market price fluctuations of natural gas, NGLs and crude oil, we use commodity derivative instruments such as futures contracts, swaps and options to manage market risk of existing or anticipated purchases and sales of natural gas, NGLs and crude oil. We adhere to policies and procedures that limit our exposure to market risk from open positions and that monitor our market risk exposure.

Our distribution segment uses storage to minimize the volatility of natural gas costs by placing natural gas in storage during the summer months for consumption in the winter months. In addition, various natural gas supply contracts allow us the option to convert index-based purchases to fixed prices. Also, we use derivative instruments to hedge the cost of anticipated natural gas purchases during the winter heating months to protect Kansas Gas Services' customers from upward volatility in the market price of natural gas.

We could be subject to claims arising out of our ownership of a majority of the general partnership interest in Northern Border Partners, LP, a publicly traded limited partnership.

In November 2004, we acquired Northern Plains, which owns 82.5 percent of the general partnership interest and 500,000 limited partnership units, together representing a 2.73 percent ownership interest, in Northern Border Partners, a publicly traded limited partnership. As the holder of a majority of the general partnership interests in Northern Border Partners we have certain duties and responsibilities. Although we do not expect to incur any material liability relating to such duties or responsibilities, we cannot provide assurance that such claims will not arise or that any claims that do arise will not have an adverse effect on our business, financial condition or results of operation.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 2. PROPERTIES

DESCRIPTION OF PROPERTIES

Gathering and Processing

We own and operate, lease and operate, or own an interest in natural gas processing plants in Oklahoma and Kansas with active processing capacity of approximately 1.7 Bcf/d and NGL fractionation capacity of 89 MBbls/d. We own approximately 10,100 miles of gathering pipelines that supply our gas processing plants.

Our natural gas processing operations utilize two types of gas processing plants - field plants and straddle plants. Our processing plants extract NGLs and remove water vapor and other contaminants from the raw natural gas stream. Our field plants located in Oklahoma and Kansas, which represent 34 percent of our processing capacity, aggregate gathered volumes of unprocessed gas from multiple producing wells into quantities that can be processed. Our straddle plants, which represent about 66 percent of our processing capacity, are situated on mainline natural gas pipelines in Kansas and allow us to extract NGLs under contract from a natural gas stream.

Natural Gas Liquids

We own and operate, or utilize through affiliated companies, approximately 4,600 miles of gathering and distribution pipelines with gathering capacity of 277 MBbls/d and distribution capacity of 360 MBbls/d. Our gathering pipelines, or those of our affiliates, are connected to approximately 90 percent of the natural gas processing plants located in the mid-continent producing areas.

We have approximately 380 MBbls/d of fractionation capacity through our ownership or interest in four different facilities. Our fractionation and storage facilities are centrally located and provide flexible redelivery of NGL products to the NGL market centers in Conway, Kansas and Mont Belvieu, Texas. We have the ability to satisfy our customer redelivery requests to these market centers, and through our own account we can also market our NGL products to the highest value locations. We own or lease approximately 20.4 MMBbls of storage capacity in the mid-continent and gulf coast regions.

Pipelines and Storage

We own approximately 5,600 miles of natural gas transmission and gathering pipelines and about 2,500 miles of natural gas liquids gathering and distribution pipelines all located in Oklahoma, Kansas and Texas. We have a peak natural gas transportation capacity of 2.9 Bcf/d and have natural gas compression and dehydration facilities located at various points throughout the pipeline system. We have a peak NGL transportation capacity of 355 MBbls/d with pump stations located at various points throughout the pipeline system.

In addition, we own or reserve capacity in five underground natural gas storage facilities in Oklahoma, three underground natural gas storage facilities in Kansas and three underground natural gas storage facilities in Texas. The storage facilities primarily consist of land and leasehold agreements with mineral and surface owners, wells and equipment, rights of way, and cushion gas. The active working storage capacity of these facilities is approximately 51.6 Bcf. Four of the Oklahoma storage facilities are located in close proximity to large market areas.

Our natural gas pipelines and storage facilities interconnect with 31 different intrastate and interstate companies at 109 interconnect points, connecting 37 processing plants and 139 producing fields. Our natural gas liquids gathering pipelines interconnect with 18 processing plants providing our customers with access to multiple markets and allowing product to be moved throughout the mid-continent and Texas panhandle areas. Our natural gas liquids distribution lines move product from fractionators in Oklahoma and Kansas to market centers in Conway, Kansas and Mont Belvieu, Texas.

Energy Services

In the third quarter of 2005, we made the decision to sell our Spring Creek power plant and exit the power generation business. These assets were held for sale at December 31, 2005, and, accordingly, this component of our business is accounted for as discontinued operations, in accordance with Statement of Financial Accounting Standards No. 144, “Accounting for the Impairment or Disposal of Long-Lived Assets” (Statement 144). For additional information see discussion of discontinued operations on page 43.

Our total storage capacity under lease is 86 Bcf, with maximum withdrawal capability of 2.3Bcf/d and maximum injection capability of 1.6 Bcf/d. Our current transportation capacity is 1.9 Bcf/d. The contracted storage and transportation capacity connects the major supply and demand centers throughout the United States and into Canada. Our storage leases are spread across eighteen different facilities in seven states and one facility in Canada allowing us the flexibility to capture volatility in the energy markets.

Distribution

We own approximately 17,800 miles of pipeline and other distribution facilities in Oklahoma, approximately 12,400 miles of pipeline and other distribution facilities in Kansas and approximately 9,000 miles of pipeline and other distribution facilities in Texas. We own a number of warehouses, garages, meter and regulator houses, service buildings and other buildings throughout Oklahoma, Kansas and Texas. We also own or lease a fleet of trucks and maintain an inventory of spare parts, equipment and supplies.

Other

We own a parking garage and land, subject to a long-term ground lease. Located on this land is a seventeen-story office building with approximately 517,000 square feet of net rentable space. We also lease our office building under a lease term that expires in 2009 with six five-year renewal options. After the primary term or any renewal period, we can purchase the property at its fair market value. We occupy approximately 240,000 square feet for our own use and lease the remaining space to others.

ITEM 3. LEGAL PROCEEDINGS

United States ex rel. Jack J. Grynberg v. ONEOK, Inc., et al., No. CIV-97-1006-R, United States District Court for the Western District of Oklahoma, transferred, In re Natural Gas Royalties Qui Tam Litigation, MDL Docket No. 1293, United States District Court for the District of Wyoming. We, along with two of our subsidiaries, were served on June 21, 1999 as defendants in an action brought under the False Claims Act by Mr. Grynberg, ostensibly on behalf of the United States. Approximately 70 other substantially identical lawsuits were filed against other companies in the natural gas industry. The main claim against the defendants alleges that they intentionally provided false information to the government concerning the volume and heating content of natural gas produced from lands in which the Federal Government or Native Americans owned the royalty rights. Grynberg seeks to recover $5,000 to $10,000 for each violation of the False Claims Act as well as treble damages for any underpayment. The actions brought by Grynberg have been transferred to the United States District Court for the District of Wyoming for coordination of pretrial proceedings. That Court overruled the defendants' initial motion to dismiss, but granted the motion of the United States to dismiss certain portions of the complaints. On June 4, 2004, we joined with the numerous other defendants in filing a motion to dismiss contending that Grynberg has not satisfied the unique jurisdictional prerequisites for maintaining an action under the False Claims Act. That motion to dismiss was heard by the Special Master on March 16 and 17, 2005. The Special Master issued his Report and Recommendation on May 16, 2005, recommending in part that all claims against the Company be dismissed. After extensive briefing, the District Court heard oral argument on December 9, 2005, on whether the Special Master's recommendations should be accepted. The Court has taken the matter under advisement.

Will Price, et al. v. Gas Pipelines, et al. (f/k/a Quinque Operating Company, et al. v. Gas Pipelines, et al.), 26th Judicial District, District Court of Stevens County, Kansas, Civil Department, Case No. 99C30 ("Price I"). Plaintiffs brought suit on May 28, 1999, against us, five of our subsidiaries and one of our divisions, as well as approximately 225 other defendants. Additionally, in connection with the completion of our acquisition of the natural gas liquids (NGL) businesses owned by several Koch companies, on July 1, 2005, we acquired Koch Hydrocarbon, LP (renamed ONEOK Hydrocarbon, L.P.) which is also one of the defendants in this case. Plaintiffs sought class certification for its claims that the defendants had underpaid gas producers and royalty owners throughout the United States by intentionally understating both the volume and the heating content of purchased gas. After extensive briefing and a hearing, the Court refused to certify the class sought by plaintiffs. Plaintiffs then filed an amended petition limiting the purported class to gas producers and royalty owners in Kansas, Colorado and Wyoming and limiting the claim to undermeasurement of volumes. Oral argument on the plaintiffs' motion to certify this suit as a class action was conducted on April 1, 2005. The Court has not yet ruled on the class certification issue.

Will Price and Stixon Petroleum, et al. v. Gas Pipelines, et al., 26th Judicial District, District Court of Stevens County, Kansas, Civil Department, Case No. 03C232 ("Price II"). This action was filed by the plaintiffs on May 12, 2003, after the Court had denied class status in Price I. Plaintiffs claim that 21 groups of defendants, including us and four of our subsidiaries, intentionally underpaid gas producers and royalty owners by understating the heating content of purchased gas in Kansas, Colorado and Wyoming. Additionally, in connection with the completion of our acquisition of the natural gas liquids (NGL) businesses owned by several Koch companies, on July 1, 2005, we acquired Koch Hydrocarbon, LP (renamed ONEOK Hydrocarbon, L.P.) which is also one of the defendants in this case. Price II has been consolidated with Price I for the determination of whether either or both cases may properly be certified as class actions. Oral argument on the plaintiffs' motion to certify this suit as a class action was conducted on April 1, 2005. The Court has not yet ruled on the class certification issue.

In the Matter of the Natural Gas Explosion at Hutchinson, Kansas during January, 2001, Case No. 02-E-0155, before the Secretary of the Kansas Department of Health and Environment. On July 23, 2002, the Division of Environment of the Kansas Department of Health and Environment (KDHE) issued an administrative order that assessed a $180,000 civil penalty against our Kansas Gas Service division. The penalty was based upon allegations of violations of various KDHE regulations relating to our operation of hydrocarbon storage wells, monitoring requirements applicable to stored hydrocarbon products, and spill reporting in connection with the gas explosion at our Yaggy gas storage facility in Hutchinson, Kansas in January 2001. In addition, the order required us to monitor existing unplugged vent wells, drill additional observation, monitoring and vent wells as directed by the KDHE, perform cleanup activities relating to certain brine wells, and prepare a geoengineering plan with respect to the Yaggy gas field. On April 5, 2004, we entered into a Consent Order with the KDHE in which we paid a civil penalty in the amount of $180,000 and reimbursed the KDHE for its costs related to the investigation of the incident in the amount of approximately $79,000. Remediation required under the consent order is ongoing.

Loyd Smith, et al v. Kansas Gas Service Company, Inc., ONEOK, Inc., Western Resources, Inc., Mid Continent Market Center, Inc., ONEOK Gas Storage, L.L.C., ONEOK Gas Storage Holdings, Inc., and ONEOK Gas Transportation, L.L.C., Case No. 01-C-0029, in the District Court of Reno County, Kansas, and Gilley et al. v. Kansas Gas Service Company, Western Resources, Inc., ONEOK, Inc., ONEOK Gas Storage, L.L.C., ONEOK Gas Storage Holdings, Inc., ONEOK Gas Transportation L.L.C. and Mid Continent Market Center, Inc., Case No. 01-C-0057, in the District Court of Reno County, Kansas. Two separate class action lawsuits were filed against us and several of our subsidiaries in early 2001 relating to certain gas explosions in Hutchinson, Kansas. The court certified two separate classes of claimants, which included all owners of residential real estate in Reno County, Kansas whose property had allegedly declined in value, and owners of businesses in Reno County whose income had allegedly suffered. Both cases were adjudicated in September 2004 and resulted in jury verdicts. In the class action relating to the residential claimants, the jury awarded $5 million in actual damages, which is covered by insurance. In the business owners' class action, the jury rendered a defense verdict awarding no actual damages. The jury rejected claims for punitive damages in both cases. In a separate hearing on Plaintiffs' attorney fees, the Judge awarded $2,047,406 in fees and $646,090.78 in expenses, which is also covered by insurance. We are reviewing our options for appeal of the residential claimants' class action verdict and subsequent award of attorney fees. With the exception of a related lawsuit that was filed in Sedgwick County, Kansas, which is now on appeal (see Note K of the Notes to Consolidated Financial Statements included in this Annual Report on Form 10-K for additional discussion on this matter), all other litigation regarding the gas explosions has been resolved. On April 11, 2005, the court denied plaintiffs' motion for a new trial and denied a post trial motion filed by defendants. The business class plaintiffs and residential class plaintiffs have filed notices of appeal. We have filed a notice of appeal of the residential class verdict and the attorney fee award. The cases have been transferred to the Kansas Supreme Court for appeal.

Cornerstone Propane Partners, L.P., et al. v. E Prime, Inc., ONEOK Energy Marketing and Trading Company, L.P., ONEOK, Inc., and Calpine Energy services, L.P., United States District Court for the Southern District of New York, Case No. 04-CV-00758. We and our wholly owned subsidiary, ONEOK Energy Services, L.P. (formerly ONEOK Energy Marketing and Trading Company, L.P.) were named as two of the defendants in the above-captioned lawsuit filed February 2, 2004, in the United States District Court for the Southern District of New York brought on behalf of persons who bought and sold natural gas futures and options contracts on the New York Mercantile Exchange during the years 2000 through 2002. The Complaint seeks class certification, actual damages in unspecified amounts for alleged violations of the Commodities Exchange Act, recovery of costs of the suit, including attorney's fees, and other appropriate relief. On August 17, 2004, this case was consolidated for all purposes with a related lawsuit, which names a number of other defendants in the energy industry. Plaintiffs in the related case assert allegations similar to those alleged against us in this case. On October 3, 2005, the Court granted plaintiffs' motion for class certification without a hearing. On February 3, 2006, plaintiffs' filed a motion for preliminary approval of the proposed settlement with certain defendants, including the ONEOK entities. The Court approved Plaintiffs motion on February 8, 2006.

Enron Corp. v. Silver Oak Capital, LLC and AG Capital Recovery Partners III, LP, Adversary Proceeding No. 03-93568, relating to Case No. 01-16034, in the United States Bankruptcy Court for the Southern District of New York. Enron Corp. filed a complaint on November 28, 2003, against Silver Oak Capital, LLC and AG Capital Recovery Partners III, LP ("AG"), instituting an adversary proceeding seeking to avoid as a fraudulent transfer, under Section 548 of the Bankruptcy Code, certain guaranties of obligations of Enron North America Corp. ("ENA") that Enron Corp. issued to one of our subsidiaries, ONEOK Energy Services, L.P. (formerly ONEOK Energy Marketing and Trading Company, L.P.). At that time, AG was the owner of claims filed in the bankruptcies of Enron Corp. and ENA that ONEOK Energy Services, L.P. originally sold on a recourse basis to Bear Stearns & Co. Inc. in May 2002 (the "Claims"). The filing of that complaint triggered repurchase obligations that ONEOK Energy Services, L.P. honored in April 2004, and accordingly ONEOK Energy Services, L.P. purchased from AG $25 million of the Claims against Enron Corp. (the "Repurchased Claims"). ONEOK Energy Services, L.P. now owns and is enforcing the Repurchased Claims in the Enron bankruptcy case, and ONEOK Energy Services, L.P. is also defending the adversary proceeding. Additionally, Enron Corp. and ENA have filed separate objections to a portion of the Claims, alleging that the applicable proofs of claim, as filed by AG, were overstated. The filing of those objections may trigger obligations of ONEOK Energy Services, L.P. to repurchase additional portions of the Claims (the "Additional Contested Claims"), which ONEOK Energy Services, L.P. would then enforce in the same manner as the Repurchased Claims. If ONEOK Energy Services, L.P. did repurchase some or all of the Additional Contested Claims, it would then potentially be entitled to distributions under the confirmed Enron bankruptcy plan on account of those claims that would be less than the amount for which ONEOK Energy Services, L.P. might have to repurchase the Additional Contested Claims.

Samuel P. Leggett, et al. v. Duke Energy Corporation et al; Case No. 13847 in the Chancery Court of Tennessee for the Twenty-Fifth Judicial District at Somerville. This action was filed against us and our wholly owned subsidiary, ONEOK Energy Services Company (formerly ONEOK Energy Marketing and Trading Company, L.P.) and several other energy trading companies on January 28, 2005. The lawsuit seeks a class certification of residential and business classes in

Tennessee for recovery of damages and injunctive relief based upon allegations of a purported conspiracy to manipulate the price of gas in Tennessee through the reporting of false prices to the publishers of natural gas price indexes and other misconduct. On March 7, 2005, the defendants removed this matter to federal court. On August 11, 2005, the Judicial Panel on Multidistrict Litigation transferred the case to the District of Nevada for inclusion in the multidistrict litigation styled "*In Re Western States Wholesale Natural Gas Antitrust Litigation*" (MDL-1566). The plaintiffs have filed a motion to remand the case to state court, and defendants have moved to dismiss the case. Both motions are currently pending in the MDL proceeding.

Learjet, Inc., et al. v. ONEOK, Inc., et al., originally filed in the District Court of Wyandotte County, Kansas (Case No. 05-CV-1500), removed to the United States District Court for the District of Kansas (Case No. 05-CV-2513-CM-JPO), conditionally transferred to MDL-1566 in the United States District Court for the District of Nevada. This class action was brought on November 4, 2005 on behalf of Kansas direct purchasers of natural gas against ONEOK, Inc., ONEOK Energy Services Company, L.P., Kansas Gas Marketing Company, and 20 other defendants. The plaintiffs allege, among other things, that during the period from January 1, 2000 through October 31, 2002, the defendants violated the Kansas Restraint of Trade Act by reporting false prices to publishers of natural gas price indexes that increased the price paid for natural gas purchased by the plaintiffs. The plaintiffs seek damages based upon the full consideration damage remedy of the Kansas Restraint of Trade Act, together with court costs and attorney fees. The case was removed from state district court to federal district court on December 7, 2005. The Judicial Panel for Multidistrict Litigation issued a conditional transfer order on January 23, 2006, conditionally transferring this case to MDL Docket No. 1566 pending in the United States District Court for the District of Nevada. The Plaintiffs filed a Motion to Vacate the Conditional Transfer Order with the Judicial Panel on Multidistrict Litigation on February 7, 2006.

Sinclair Oil Corporation v. ONEOK Energy Services Corporation, L.P., filed in the United States District Court for the District of Wyoming (Case No. 05-CV-254-D), conditionally transferred to MDL-1566 in the United States District Court for the District of Nevada (Case No. 05-CV-1396). On September 23, 2005, Sinclair Oil Corporation filed a complaint asserting several claims against ONEOK Energy Services Company, L.P. ("OESC") on alleged misconduct for false reporting to publishers of natural gas price indexes. Sinclair was a gas purchaser from OESC and claims the false reporting affected the price it paid for gas. A motion to dismiss the case based on the defenses of the filed rate doctrine and federal preemption was filed on November 3, 2005. The Judicial Panel on Multidistrict Litigation entered a conditional transfer order on November 4, 2005, conditionally transferring this case to the Multidistrict Litigation Docket No. 1566 in the United States District Court for the District of Nevada. The Judicial Panel for Multidistrict Litigation entered into a final Order on February 15, 2006, transferring this case to MDL Docket No. 1566 pending in the United Sates District Court for the District of Nevada.

J.P. Morgan Trust Company v. ONEOK, Inc., et al, originally filed in the District Court of Wyandotte County (Case No. 05-CV-1232), removed to the United States District Court for the District of Kansas (Case No. 05-CV-1331), transferred to MDL-1566 in the United States District Court for the District of Nevada (Case No. 05-CV-1331). On October, 2005, an amended complaint was filed in this case naming ONEOK, Inc. and ONEOK Energy Marketing and Trading Company, L.P. (now named ONEOK Energy Services Company, L.P.) as defendants. The amended complaint asserts claims under the Kansas Restraint of Trade Act against 22 defendants. On October 13, 2005, the Judicial Panel on Multidistrict Litigation entered a conditional transfer order of this case to MDL Docket No. 1566 pending in the United States District Court for the District of Nevada. On March 2, 2006, the Court granted the Motion for Remand filed by the plaintiff. However, the Court has stayed this order pending a further review. The case had been transferred to the MDL 1566 proceeding and if the remand order stands, will be remanded back to the District Court of Wyandotte County, Kansas.

Richard Manson v. Northern Plains Natural Gas Company, LLC, et. al., Civil Action No. 1973-N, in the Court of Chancery of the State of Delaware in and for New Castle County. On March 2, 2006, a holder of limited partnership units of Northern Border Partners, L.P. ("Northern Border") filed a class action and derivative complaint on behalf of a putative class of all holders of Northern Border limited partnership units against Northern Border, TransCanada Corporation, us and some of our affiliates, and the individual members of the Policy Committee of Northern Border. The plaintiff claims that the transactions we announced on February 15, 2006, including the sale of some of our assets to Northern Border, an increase of our general partner interest in Northern Border to 100 percent and the sale by Northern Border of 20 percent of its interest in Northern Border Pipeline Company to TC PipeLines, LP, will constitute a breach of Northern Border's partnership agreement and a breach of defendants' fiduciary duties. The plaintiff seeks to enjoin the transactions or to rescind them if the transactions are completed prior to entry of a final judgment in the case. The Plaintiff also seeks to recover damages on behalf of the class for the profits and any special benefits obtained by the defendants, as well as interest, costs, attorneys' fees and expert fees.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matter was submitted to a vote of our security holders, through the solicitation of proxies or otherwise, during the fourth quarter of the fiscal year covered by this report.

PART II.

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

MARKET INFORMATION AND HOLDERS

Our common stock is listed on the New York Stock Exchange under the trading symbol OKE. The corporate name ONEOK is used in newspaper stock listings. The following table sets forth the high and low closing prices of our common stock for the periods indicated.

	Year Ended December 31, 2005		Year Ended December 31, 2004	
	High	**Low**	**High**	**Low**
First Quarter	**$ 30.94**	**$ 27.10**	$ 23.37	$ 21.74
Second Quarter	**$ 32.65**	**$ 28.68**	$ 22.93	$ 19.80
Third Quarter	**$ 35.72**	**$ 32.36**	$ 26.02	$ 20.97
Fourth Quarter	**$ 34.68**	**$ 26.63**	$ 28.90	$ 25.66

There were 14,724 holders of record of our common stock at February 28, 2006.

DIVIDENDS

The following table sets forth the quarterly dividends paid on our common stock during the periods indicated.

	Years Ended December 31,			
	2005		**2004**	
First Quarter	**$ 0.25**		$ 0.19	
Second Quarter	**$ 0.28**		$ 0.21	
Third Quarter	**$ 0.28**	(a)	$ 0.23	(a)
Fourth Quarter	**$ 0.28**	(a)	$ 0.25	(a)

(a) - Declared in the previous quarter.

EQUITY COMPENSATION PLAN INFORMATION

The following table sets forth certain information concerning our equity compensation plans as of December 31, 2005.

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available For Future Issuance Under Equity Compensation Plans (Excluding Securities in Column (a)) (c)
Equity compensation plans approved by security holders (1)	2,805,174	$21.90	2,791,688 (4)
Equity compensation plans not approved by security holders (2)	264,510	$22.73 (3)	507,219 (4)
Total	3,069,684	$21.97	3,298,907

(1) Includes stock options, restricted stock awards, restricted stock incentive units and performance share awards granted under our Long-Term Incentive Plan. For a brief description of the material features of this plan, see Note P of the Notes to Consolidated Financial Statements. Column (c) also includes 1,297,310 and 966,887 shares available for future issuance under our Thrift Plan and Employee Stock Purchase Plan, respectively.

(2) Includes our Employee Non-Qualified Deferred Compensation Plan, Deferred Compensation Plan for Non-Employee Directors, and Stock Compensation Plan for Non-Employee Directors. For a brief description of the material features of these plans, see Note P of the Notes to Consolidated Financial Statements. Column (c) also includes 42,662 shares available for future issuance under the Employee Stock Award Program described below.

(3) Compensation deferred into our common stock under our Employee Non-Qualified Deferred Compensation Plan and Deferred Compensation Plan for Non-Employee Directors is distributed to participants at fair market value on the date of distribution. The price used for these plans to calculate the weighted-average exercise price in the table is $26.63, which represents the closing price of our common stock at December 30, 2005.

(4) Securities reserved for future issuance under our Deferred Compensation Plan for Non-Employee Directors are included in shares reserved for issuance under our Long-Term Incentive Plan, which is reflected in the table as an equity compensation plan approved by security holders.

ISSUER PURCHASES OF EQUITY SECURITIES

The following table sets forth information relating to our purchases of our common stock for the periods shown.

Period	Total Number of Shares Purchased		Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs	
October 1-31, 2005	11,447	(1) (2)	$31.27	1,200,900	267,500	
November 1-30, 2005	78	(1) (2)	$27.57	267,500	7,500,000	(3)
December 1-31, 2005	6,704	(1) (2)	$26.80	-	7,500,000	
Total	18,229		$29.61	1,468,400	7,500,000	

(1) Includes shares withheld pursuant to attestation of ownership and deemed tendered to us in connection with the exercise of stock options under the ONEOK, Inc. Long-Term Incentive Plan, as follows :
11,412 shares for the period October 1-31, 2005
6,662 shares for the period December 1-31, 2005

(2) Includes shares repurchased directly from employees, pursuant to our Employee Stock Award Program, as follows:
35 shares for the period October 1-31, 2005
78 shares for the period November 1-30, 2005
42 shares for the period December 1-31, 2005

(3) Reflects additional shares authorized by our Board of Directors in November 2005.

EMPLOYEE STOCK AWARD PROGRAM

Under our Employee Stock Award Program, we issued, for no consideration, to all eligible employees (all full-time employees and employees on short-term disability) one share of our common stock when the closing price of our common stock on the New York Stock Exchange (NYSE) was for the first time at or above $26 per share, and we will issue, for no consideration, one additional share of our common stock to all eligible employees when the closing price on the NYSE is for the first time at or above each one dollar increment above $26 per share. In July 2005, our Board increased the total number of shares of our common stock available for issuance under this program from 50,000 to 100,000.

Through December 31, 2005, a total of 45,415 shares had been issued to employees under this program.

The issuance of shares under this program has not been registered under the Securities Act of 1933, as amended (1933 Act) in reliance upon SEC releases, including Release No. 6188, dated February 1, 1980, stating that there is no sale of the shares in the 1933 Act sense to employees under this type of program.

ITEM 6. SELECTED FINANCIAL DATA

Through February 5, 2003, we computed our earnings per share (EPS) in accordance with EITF Topic No. D-95 (Topic D-95), which was subsequently superceded by EITF Issue No. 03-6, “Participating Securities and the Two-Class Method under FASB Statement No. 128”. See Note Q of the Notes to our Consolidated Financial Statements in this Annual Report on Form 10-K for additional information.

In February 2003, we purchased approximately 9 million shares of our Series A Convertible Preferred Stock (Series A) from Westar and exchanged the remaining 10.9 million shares of Series A for 21.8 million shares of Series D Convertible Preferred Stock (Series D) reflecting the two-for-one stock split in 2001. The Series D had a fixed annual cash dividend rate of 92.5 cents per share. As a result of this transaction, the EITF for participating securities no longer applied to our computation of EPS beginning in February 2003. In November 2003, the Series D was converted to common stock and sold to the public by Westar. Effective January 6, 2004, the Series D was retired. There are no shares of Series A currently outstanding.

The following table sets forth our selected financial data for each of the periods indicated.

	Years Ended December 31,				
	2005	**2004**	**2003**	**2002**	**2001**
	(Millions of dollars, except per share amounts)				
Net margin from continuing operations	**$ 1,338.2**	$ 1,137.2	$ 1,084.8	$ 875.3	$ 699.2
Operating income from continuing operations	**$ 799.0**	$ 443.7	$ 427.9	$ 346.1	$ 194.2
Income from continuing operations	**$ 403.1**	$ 224.7	$ 206.4	$ 151.0	$ 43.5
Total assets	**$ 10,013.5**	$ 7,199.2	$ 6,211.9	$ 5,809.6	$ 5,853.3
Long-term debt	**$ 1,993.2**	$ 1,829.5	$ 1,830.9	$ 1,442.0	$ 1,744.2
Basic earnings per share - continuing operations	**$ 4.01**	$ 2.21	$ 2.28	$ 1.26	$ 0.36
Basic earnings per share - total	**$ 5.44**	$ 2.38	$ 1.48	$ 1.40	$ 0.85
Diluted earnings per share - continuing operations	**$ 3.73**	$ 2.13	$ 2.05	$ 1.26	$ 0.36
Diluted earnings per share - total	**$ 5.06**	$ 2.30	$ 1.22	$ 1.39	$ 0.85
Dividends declared per common share	**$ 1.09**	$ 0.88	$ 0.69	$ 0.62	$ 0.62

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION

EXECUTIVE SUMMARY

The following discussion highlights some of our achievements and significant issues affecting us this past year. You should read the Financial and Operating Results section of Management's Discussion and Analysis of Financial Condition and Results of Operation and the Financial Statements for a complete explanation of the following items.

Our diluted earnings per share of common stock from continuing operations increased to $3.73 in 2005 compared with $2.13 in 2004. During 2005, we increased our dividend to a current annual dividend of $1.12 per share of common stock. This follows four increases in our dividend during 2004.

In 2005, our income from continuing operations increased to $403.1 million from $224.7 million in 2004, a 79 percent increase. Operating income increased to $799.0 million in 2005 from $443.7 million in 2004, primarily due to the gain on sale of assets in our Gathering and Processing segment of $264.2 million.

Our Energy Services segment benefited from increases in natural gas prices and price volatility during 2005. Operating income for our Energy Services segment increased $26.5 million in 2005 compared with 2004, primarily due to an increase of $32.4 million in net margin. An increase of $41.9 million in net margin was due to the effect of improved natural gas basis differentials on transportation margins. A $22.6 million increase in net margin was due to the increase in wholesale physical marketing margins, which resulted from natural gas price volatility. These increases were partially offset by an $18.3 million decrease in storage margins from cash flow hedge ineffectiveness primarily related to natural gas basis movements attributable to anticipated storage withdrawals from the 2006/2007 heating season and an $18.4 million decrease resulting from less favorable price movements in 2005 related to our natural gas fixed price activities.

Favorable energy prices also had a significant impact on our Gathering and Processing segment's results during 2005. Average prices for natural gas, NGLs and crude oil exceeded prices for the same period in 2004. The gross processing spread was also higher in 2005 and continued to exceed the previous five-year and three-year averages.

The acquisition of the natural gas liquids businesses owned by several affiliates and a subsidiary of Koch in July 2005, accounted for increases in both our Natural Gas Liquids segment and our Pipelines and Storage segment.

On February 14, 2006, we signed agreements to sell certain assets to Northern Border Partners for approximately $3 billion in cash and limited partner units and increase our general partnership interest in Northern Border Partners to 100 percent. We expect these transactions to be completed by April 1, 2006. These transactions will result in our Gathering and Processing segment, Natural Gas Liquids segment, and Pipelines and Storage segment being transferred to Northern Border Partners.

On October 4, 2005, the OCC issued a final order on our application for a rate increase by Oklahoma Natural Gas. The OCC unanimously approved an annual rate increase of $57.5 million. The Commission's administrative law judge had previously recommended an increase in annual revenues of approximately $58.0 million in July 2005. Oklahoma Natural Gas implemented new rates, subject to refund, on July 28, 2005, based on the judge's report.

SIGNIFICANT ACQUISITIONS AND DIVESTITURES

In February 2006, we signed agreements to sell certain assets to Northern Border Partners for approximately $3 billion in cash and limited partner units and increase our general partner interest in Northern Border Partners to 100 percent. We will purchase, through Northern Plains, from an affiliate of TransCanada Corporation (TransCanada) 17.5 percent of the general partner interest in Northern Border Partners for $40 million, less $10 million for expenses associated with the transfer of operating responsibility of the Northern Border Pipeline Company to TransCanada for a net payment of $30 million. After the transactions are completed, we will own approximately 37.0 million limited partner units and 100 percent of the Northern Border Partners' general partner interest, increasing our total interest in Northern Border Partners to 45.7 percent.

With the purchase of 17.5 percent of the general partner interest in Northern Border Partners, we will also transfer our Gathering and Processing segment, Natural Gas Liquids segment, and Pipelines and Storage segment to Northern Border Partners in transactions valued at approximately $3 billion. We will receive approximately $1.35 billion in cash and approximately 36.5 million limited partner units from Northern Border Partners. The limited partner units and related general partner interest contribution were valued at approximately $1.65 billion at the time of the signing of the transaction. This sale, subject to adjustment, includes the natural gas liquids assets we purchased from Koch in July 2005 for $1.35 billion. We will not recognize a gain on the sale as the transfer of assets will be accounted for at the assets' historical cost.

We plan to use the cash proceeds to reduce short-term debt, acquire other assets or repurchase our common stock. These transactions are subject to regulatory approvals and other conditions, including antitrust clearance from the Federal Trade Commission under the Hart-Scott-Rodino Act. We expect these transactions to be completed by April 1, 2006.

In December 2005, we sold our natural gas gathering and processing assets located in Texas to a subsidiary of Eagle Rock Energy, Inc. for approximately $527.2 million and recorded a pre-tax gain of $264.2 million, which is included in gain on sale of assets in our Gathering and Processing segment's operating income. The gain reflects the cash received less adjustments, selling expenses and the net book value of the assets sold. We used the net cash proceeds from this sale to prepay our 7.75 percent $300.0 million long-term debt which was due in August 2006.

In October 2005, we entered into an agreement to sell our Spring Creek power plant to Westar for $53 million. The transaction requires FERC approval and is expected to be completed in 2006. The 300-megawatt gas-fired merchant power plant was built in 2001 to supply electrical power during peak periods using gas-powered turbine generators. The financial information related to the properties sold is reflected as a discontinued component in this Annual Report on Form 10-K. All periods presented have been restated to reflect the discontinued component.

In September 2005, we completed the sale of our Production segment to TXOK Acquisition, Inc. for $645 million, before adjustments and recognized a pre-tax gain on the sale of approximately $240.3 million. The gain reflects the cash received less adjustments, selling expenses and the net book value of the assets sold. The proceeds from the sale were used to reduce debt. The financial information related to the properties sold is reflected as a discontinued component in this Annual Report on Form 10-K. All periods presented have been restated to reflect the discontinued component.

In July 2005, we completed the acquisition of the natural gas liquids businesses owned by Koch for approximately $1.33 billion, net of working capital and cash received. This transaction included Koch Hydrocarbon, LP's entire mid-continent natural gas liquids fractionation business; Koch Pipeline Company, LP's natural gas liquids pipeline distribution systems; Chisholm Pipeline Holdings, Inc., which has a 50 percent ownership interest in Chisholm Pipeline Company; MBFF, LP, which owns an 80 percent interest in a 160,000 barrel per day fractionator at Mont Belvieu, Texas; and Koch Vesco Holdings, LLC, an entity that owns a 10.2 percent interest in VESCO. These assets are included in our consolidated financial statements beginning on July 1, 2005.

In November 2004, we acquired Northern Plains, which owns 82.5 percent of the general partner interest and 500,000 limited partnership units, together representing a 2.73 percent ownership interest, in Northern Border Partners, from CCE Holdings, LLC for $175 million. Income derived from this investment is included in other income in our Other segment.

In December 2003, we acquired approximately $240 million of natural gas and crude oil properties and related flow lines located in Texas. The results of operations for these assets were included in our consolidated financial statements from that date until the disposition of our Production segment in September 2005.

In January 2003, we sold approximately 70 percent of the natural gas and crude oil producing properties of our Production segment for an adjusted cash price of $294 million. The properties sold were located in Oklahoma, Kansas and Texas. We recorded a pretax gain of approximately $61.2 million in 2003 related to this sale. The financial information related to the properties sold is reflected as a discontinued component in this Annual Report on Form 10-K.

In January 2003, we acquired the Texas natural gas distribution business and other assets from Southern Union Company. The results of operations for these assets have been included in our consolidated financial statements since that date. We paid approximately $436.6 million for these assets, including $16.6 million in working capital adjustments. The primary assets acquired were natural gas distribution operations that currently serve approximately 560,000 customers in cities located throughout Texas, including the major cities of El Paso and Austin, as well as the cities of Port Arthur, Galveston, Brownsville and others. Over 90 percent of the customers are residential. The other assets acquired include a 125-mile natural gas transmission system, as well as other energy-related domestic assets involved in natural gas marketing, retail sales of propane and distribution of propane. The purchase also included natural gas distribution investments in Mexico. The assets relating to the propane distribution operations were sold in May and July 2004, and the natural gas distribution investments in Mexico were sold in May 2004.

REGULATORY

Several regulatory initiatives positively impacted the earnings and future earnings potential for our Distribution segment. These are discussed beginning on page 42.

IMPACT OF NEW ACCOUNTING STANDARDS

In December 2004, the FASB issued Statement of Financial Accounting Standards No. 123R, “Share-Based Payment” (Statement 123R). Statement 123R requires companies to expense the fair value of share-based payments. In addition, there are also changes related to the expense calculation for share-based payments. Effective January 1, 2006, we adopted Statement 123R, and we elected to use the prospective method. We are currently assessing the impact of adopting Statement 123R, but we do not believe it will have a material impact on our financial condition and results of operations, as we have been expensing share-based payments since our adoption of Statement of Financial Accounting Standards No. 148, “Accounting for Stock-Based Compensation - Transition and Disclosure” on January 1, 2003.

In March 2005, the FASB issued Interpretation No. 47, “Accounting for Conditional Asset Retirement Obligations” (FIN 47), that requires an entity to recognize a liability for the fair value of a conditional asset retirement obligation when incurred if the liability’s fair value can be reasonably estimated. FIN 47 is effective for our year ended December 31, 2005. We completed our review of the applicability of FIN 47 to our operations and determined that its impact was immaterial to our consolidated financial statements.

In June 2005, the FASB ratified the consensus reached in EITF 04-5. EITF 04-5 presumes that a general partner controls a limited partnership and therefore should consolidate the partnership in the financial statements of the general partner. Effective January 1, 2006, we were required to consolidate Northern Border Partners’ operations in our consolidated financial statements and we elected to use the prospective method. If we had consolidated Northern Border Partners at December 31, 2005, our debt-to-equity ratio would have changed from 67 percent debt and 33 percent equity to 73 percent debt and 27 percent equity. This increase results from the consolidation of Northern Border Partners’ debt of $1.35 billion at December 31, 2005, while the majority of their equity is reported as minority interest liability. The debt covenant calculations in our credit agreements exclude the debt of Northern Border Partners, since it is a master limited partnership. The adoption of EITF 04-5 will not have an impact on our net income; however, reported revenues, costs and expenses will be higher to reflect the activities of Northern Border Partners.

In September 2005, the FASB ratified the consensus reached in EITF Issue No. 04-13, “Accounting for Purchases and Sales of Inventory with the Same Counterparty” (EITF 04-13). EITF 04-13 defines when a purchase and a sale of inventory with the same party that operates in the same line of business should be considered a single nonmonetary transaction. EITF 04-13 is effective for new arrangements that a company enters into in periods beginning after March 15, 2006. We do not expect the adoption of EITF 04-13 to impact our consolidated financial statements.

The FASB is currently reviewing the accounting for pension and postretirement medical benefits and expects to issue an exposure draft on phase one of this project during the first quarter of 2006. The final standard for the first phase of this project is expected to be issued in the third quarter of 2006 with implementation required for years ending after December 15, 2006. Based on the FASB’s discussion, we could be required to record a balance sheet liability equal to the difference between our benefit obligations and plan assets. If this requirement had been in place at December 31, 2005, we would have been required to record unrecognized losses of $124.8 million and $78.8 million for pension and postretirement benefits, respectively, on our consolidated balance sheet as accumulated other comprehensive income (loss).

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our discussion and analysis of financial condition and results of operations are based on our consolidated financial statements, prepared in accordance with accounting principles generally accepted in the United States of America and included in this Annual Report on Form 10-K. Certain amounts included in or affecting our financial statements and related disclosure must be estimated, requiring us to make certain assumptions with respect to values or conditions that cannot be known with certainty at the time the financial statements are prepared. Therefore, the reported amounts of our assets and liabilities, revenues and expenses and associated disclosures with respect to contingent assets and obligations are necessarily affected by these estimates. We evaluate these estimates on an ongoing basis, utilizing historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from our estimates.

The following is a summary of our most critical accounting policies, which are defined as those policies most important to the portrayal of our financial condition and results of operations and requiring management's most difficult, subjective, or complex judgment, particularly because of the need to make estimates concerning the impact of inherently uncertain matters. We have discussed the development of and selection of our critical accounting policies and estimates with the audit committee of our Board of Directors.

Derivatives and Risk Management Activities - We engage in wholesale energy marketing, retail marketing, trading, and risk management activities. We account for derivative instruments utilized in connection with these activities and services under the fair value basis of accounting in accordance with Statement of Financial Accounting Standards No. 133, “Accounting for Derivative Instruments and Hedging Activities” (Statement 133), as amended.

Under Statement 133, entities are required to record derivative instruments at fair value. The fair value of derivative instruments is determined by commodity exchange prices, over-the-counter quotes, volatility, time value, counterparty credit and the potential impact on market prices of liquidating positions in an orderly manner over a reasonable period of time under current market conditions. Refer to the table on page 53 for amounts in our portfolio at December 31, 2005, that were determined by prices actively quoted, prices provided by other external sources and prices derived from other sources. The majority of our portfolio’s fair values are based on actual market prices. Transactions are also executed in markets for which market prices may exist but the market may be relatively inactive, thereby resulting in limited price transparency that requires management’s subjectivity in estimating fair values.

Market value changes result in a change in the fair value of our derivative instruments. The accounting for changes in the fair value of a derivative instrument depends on whether it has been designated and qualifies as part of a hedging relationship and, if so, the reason for holding it. If the derivative instrument does not qualify or is not designated as part of a hedging relationship, we account for changes in fair value of the derivative in earnings as they occur. Commodity price volatility may have a significant impact on the gain or loss in any given period. For more information on fair value sensitivity and a discussion of the market risk of pricing changes, see Item 7A, Quantitative and Qualitative Disclosures about Market Risk.

To minimize the risk of fluctuations in natural gas, NGLs and crude oil prices, we periodically enter into futures transactions and swaps in order to hedge anticipated purchases of natural gas and crude oil, fuel requirements and NGL inventories. Interest rate swaps are also used to manage interest rate risk. Under certain conditions, we designate these derivative instruments as a hedge of exposure to changes in fair values or cash flows. For hedges of exposure to changes in fair value, the gain or loss on the derivative instrument is recognized in earnings in the period of change together with the offsetting loss or gain on the hedged item attributable to the risk being hedged. For hedges of exposure to changes in cash flow, the effective portion of the gain or loss on the derivative instrument is reported initially as a component of other comprehensive income and is subsequently reclassified into earnings when the forecasted transaction affects earnings. Any ineffectiveness of designated hedges is reported in earnings in the period the ineffectiveness occurs.

Many of our purchase and sale agreements that otherwise would be required to follow derivative accounting qualify as normal purchases and normal sales under Statement 133 and are therefore exempt from fair value accounting treatment.

Energy-related contracts that are not derivatives pursuant to Statement 133 are no longer carried at fair value but are accounted for on an accrual basis as executory contracts. Changes to the accounting for existing contracts as a result of the rescission of EITF Issue No. 98-10, “Accounting for Contracts Involved in Energy Trading and Risk Management Activities” were reported as a cumulative effect of a change in accounting principle on January 1, 2003. This resulted in a cumulative effect loss, net of tax, of $141.8 million in 2003.

Impairment of Goodwill and Long-Lived Assets - We assess our goodwill for impairment at least annually based on Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets" (Statement 142). An initial assessment is made by comparing the fair value of the operations with goodwill, as determined in accordance with Statement 142, to the book value of each reporting unit. If the fair value is less than the book value, an impairment is indicated, and we must perform a second test to measure the amount of the impairment. In the second test, we calculate the implied fair value of the goodwill by deducting the fair value of all tangible and intangible net assets of the operations with goodwill from the fair value determined in step one of the assessment. If the carrying value of the goodwill exceeds this calculated implied fair value of the goodwill, we will record an impairment charge. At December 31, 2005, we had the following amounts of goodwill recorded on our balance sheet.

	(Thousands of dollars)
Gathering and Processing	**$ 15,604**
Natural Gas Liquids	**173,945**
Pipelines and Storage	**22,036**
Energy Services	**10,255**
Distribution	**158,554**
Total goodwill	**$ 380,394**

We assess our long-lived assets for impairment based on Statement 144. A long-lived asset is tested for impairment whenever events or changes in circumstances indicate that its carrying amount may exceed its fair value. Fair values are based on the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the assets.

Examples of long-lived asset impairment indicators include:

- a significant decrease in the market price of a long-lived asset or asset group,
- a significant adverse change in the extent or manner in which a long-lived asset or asset group is being used or in its physical condition,
- a significant adverse change in legal factors or in the business climate that could affect the value of a long-lived asset or asset group, including an adverse action or assessment by a regulator that would exclude allowable costs from the rate-making process,
- an accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of a long-lived asset or asset group,
- a current-period operating cash flow loss, combined with a history of operating cash flow losses or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset or asset group, and
- a current expectation that, more likely than not, a long-lived asset or asset group will be sold or otherwise disposed of significantly before the end of its previously estimated useful life.

In the third quarter of 2005, we made the decision to sell our Spring Creek power plant, located in central Oklahoma, and exit the power generation business. In October 2005, we concluded that our Spring Creek power plant had been impaired and recorded an impairment expense of $52.2 million. This conclusion was based on our Statement 144 impairment analysis of the results of operations for this plant through September 30, 2005, and also the net sales proceeds from the anticipated sale of the plant. These assets were held for sale at December 31, 2005, and, accordingly, this component of our business is accounted for as discontinued operations in accordance with Statement 144.

Pension and Postretirement Employee Benefits - We have a defined benefit pension plan covering substantially all full-time employees and a postretirement employee benefits plan covering most employees. Nonbargaining unit employees hired after December 31, 2004, are not eligible for our defined benefit pension plan; however, they are covered by a profit sharing plan. Nonbargaining unit employees retiring between the ages of 50 and 55 who elect postretirement medical coverage, all nonbargaining unit employees hired on or after January 1, 1999, employees who are members of the International Brotherhood of Electrical Workers hired after June 30, 2003, and gas union employees hired after July 1, 2004, who elect postretirement medical coverage pay 100 percent of the retiree premium for participation in the plan. Additionally, any employees who came to us through various acquisitions may be further limited in their eligibility to participate or receive any contributions from us for postretirement medical benefits. Our actuarial consultant calculates the expense and liability related to these plans and uses statistical and other factors that attempt to anticipate future events. These factors include assumptions about the discount rate, expected return on plan assets, rate of future compensation increases, age and employment periods. In determining the projected benefit obligations and costs, assumptions can change from period to period and result in material changes in the costs and liabilities we recognize. See Note J of Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional information.

Assumed health care cost trend rates have a significant effect on the amounts reported for our health care plans. A one-percentage point change in assumed health care cost trend rates would have the following effects.

	One-Percentage Point Increase	One-Percentage Point Decrease
	(Thousands of dollars)	
Effect on total of service and interest cost	**$ 3,106**	**$ (2,513)**
Effect on postretirement benefit obligation	**$ 17,982**	**$ (15,619)**

During 2005, we recorded net periodic benefit costs of $13.0 million related to our defined benefit pension plans and $27.4 million related to postretirement benefits. We estimate that in 2006, we will record net periodic benefit costs of $21.9 million related to our defined benefit pension plan and $25.9 million related to postretirement benefits. In determining our estimated expenses for 2006, our actuarial consultant assumed an 8.75 percent expected return on plan assets and a discount rate of 5.75 percent. A decrease in our expected return on plan assets to 8.50 percent would increase our 2006 estimated net periodic benefit costs by approximately $1.6 million for our defined benefit pension plan and would not have a significant impact on our postretirement benefit plan. A decrease in our assumed discount rate to 5.25 percent would increase our 2006 estimated net periodic benefit costs by approximately $4.9 million for our defined benefit pension plan and $1.6 million for our postretirement benefit plan. For 2006, we anticipate our total contributions to our defined benefit pension plan and postretirement benefit plan to be $1.7 million and $2.7 million, respectively, and our pay-as-you-go other postretirement benefit plan costs to be $14.0 million.

Contingencies - Our accounting for contingencies covers a variety of business activities including contingencies for legal exposures and environmental exposures. We accrue these contingencies when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered and an amount can be reasonably estimated in accordance with Statement of Financial Accounting Standards No. 5, “Accounting for Contingencies.” We base our estimates on currently available facts and our estimates of the ultimate outcome or resolution. Actual results may differ from our estimates resulting in an impact, positive or negative, on earnings.

FINANCIAL AND OPERATING RESULTS

Consolidated Operations

The following table sets forth certain selected financial information for the periods indicated.

	Years Ended December 31,		
Financial Results	**2005**	**2004**	**2003**
		(Thousands of dollars)	
Operating revenues, excluding energy trading revenues	**$12,663,550**	$ 5,671,714	$ 2,640,684
Energy trading revenues, net	**12,680**	113,814	229,782
Cost of sales and fuel	**11,338,076**	4,648,311	1,785,648
Net margin	**1,338,154**	1,137,217	1,084,818
Operating costs	**619,995**	535,512	512,268
Depreciation, depletion and amortization	**183,394**	158,053	144,695
Gain on sale of assets	**264,207**	-	-
Operating income	**$ 798,972**	$ 443,652	$ 427,855
Other income	**$ 14,188**	$ 17,599	$ 8,128
Other expense	**$ 19,883**	$ 12,056	$ 5,198
Discontinued operations, net of taxes			
Income (loss) from operations of discontinued components, net	**$ (6,180)**	$ 17,505	$ 10,185
Gain on sale of discontinued component, net	**$ 149,577**	$ -	$ 39,739
Cumulative effect of changes in accounting principle, net of tax	**$ -**	$ -	$ (143,885)

Operating Results - Net margin increased for the year ended December 31, 2005, compared with the same period in 2004 primarily due to:

- the effect of increased natural gas basis differentials and natural gas price volatility in our Energy Services segment,
- the impact of favorable commodity pricing for natural gas and NGL products on our Gathering and Processing segment,
- the effect of the natural gas liquids assets acquired from Koch in our Natural Gas Liquids segment and our Pipelines and Storage segment, and
- the implementation of new rate schedules in Oklahoma for our Distribution segment.

For an explanation of energy trading revenues, net, see the discussion of our Energy Services segment beginning on page 37.

Consolidated operating costs for the year increased primarily because of costs related to the natural gas liquids assets acquired from Koch and increased employee benefit costs.

Depreciation, depletion and amortization increased for the year primarily due to the costs associated with the natural gas liquids assets acquired from Koch. Further increases resulted from additional plant, property and equipment in our Distribution segment and regulatory asset amortization resulting from the Kansas Gas Service rate case.

Operating income for 2005 includes the gain on sale of assets in our Gathering and Processing segment of $264.2 million. This gain was the result of the sale of certain natural gas gathering and processing assets located in Texas to a subsidiary of Eagle Rock Energy, Inc. in December 2005.

Net margin increased in 2004, compared with 2003, primarily due to:

- the impact of favorable commodity pricing for natural gas and NGL products on our Gathering and Processing segment, and
- the implementation of new rate schedules in Kansas and Oklahoma for our Distribution Segment.

These increases in net margin in 2004 compared with 2003 were partially offset by the impact of reduced volatility in natural gas prices and lower inter-regional basis spreads from marketing and seasonal gas sales from storage for our Energy Services segment.

Operating costs and depreciation, depletion and amortization increased in 2004, compared with 2003, primarily due to:

- increased employee benefit costs, and
- regulatory asset amortization resulting from the Oklahoma and Kansas rate cases.

The following table sets forth the components of other income for the periods indicated.

	Years Ended December 31,		
	2005	**2004**	**2003**
	(Thousands of dollars)		
Equity income	**$ 2,538**	$ 2,404	$ 1,489
Gains on sale of assets	**5,651**	11,269	292
Interest income	**2,686**	1,282	2,944
Income from benefit plan investments	**2,027**	1,671	2,559
Other	**1,286**	973	844
Other Income	**$ 14,188**	$ 17,599	$ 8,128

In November 2004, we acquired Northern Plains, which owns 82.5 percent of the general partnership interest and 500,000 limited partnership units, together representing a 2.73 percent ownership interest, in Northern Border Partners. Our equity income includes $10.1 million and $1.3 million in 2005 and 2004, respectively, from Northern Border Partners.

The decrease in other income for 2005 is primarily due to the impairment of $5.9 million, included in equity income, recognized in the fourth quarter of 2005 on our 50 percent investment in an Oklahoma gas plant which we do not operate. Also affecting 2005 other income is a $2.6 million impairment charge, included in equity income, related to one of our gas gathering partnerships that may terminate in early 2006.

The following table sets forth the components of other expense for the periods indicated.

	Years Ended December 31,		
	2005	**2004**	**2003**
	(Thousands of dollars)		
Donations and civic contributions	**$ 12,236**	$ 2,078	$ 5,973
Non-operating litigation expense and claims, net	**4,690**	7,033	(2,506)
Loss on sale of property	**818**	683	6
Terminated acquisition expense	**551**	401	175
Other	**1,588**	1,861	1,550
Other Expense	**$ 19,883**	$ 12,056	$ 5,198

Other expense increased in 2005, primarily due to our $10.0 million donation to the ONEOK Foundation, included in donations and civic contributions. More information regarding our results of operations is provided in the discussion of each segment's results. The discontinued component is discussed in our Discontinued Operations and Energy Services segment sections and the cumulative effect of a change in accounting principle is discussed in our Energy Services segment section.

Key Performance Indicators - Key performance indicators reviewed by management include:

- earnings per share,
- return on invested capital, and
- shareholder appreciation.

For the year ended December 31, 2005, our basic and diluted earnings per share from continuing operations was $4.01 and $3.73, respectively, representing an 81 percent increase in basic earnings per share and a 75 percent increase in diluted earnings per share from continuing operations compared with 2004. Return on invested capital is 23.0 percent in 2005 compared with 14.3 percent in 2004.

To evaluate shareholder appreciation, we compare ourselves with a group of 20 peer companies. For the three years ended December 31, 2005, we ranked in the top 50th percentile in shareholder appreciation compared to our peers.

Gathering and Processing

Overview - Our Gathering and Processing segment is engaged in the gathering and processing of natural gas and fractionation of NGLs primarily in Oklahoma and Kansas. Our operations include the gathering of natural gas production from crude oil and natural gas wells. Through gathering systems, these volumes are aggregated for removal of water vapor, solids and other contaminants and to extract NGLs in order to provide marketable natural gas, commonly referred to as residue gas. When the liquids are separated from the raw natural gas at the processing plants, the liquids are generally in the form of a mixed NGL stream. This stream can then be separated by a distillation process, referred to as fractionation, into marketable product components such as ethane, propane, iso-butane, normal butane and natural gasoline. The component products can then be stored, transported and marketed to a diverse customer base of end-users.

Acquisition and Divestiture - The following acquisition and divestiture are described beginning on page 25.

- In December 2005, we sold our natural gas gathering and processing assets located in Texas. This sale included approximately 3,700 miles of pipe and six processing plants with a capacity of 0.2 Bcf/d. See page 25 for additional information. The impact of these assets on our Gathering and Processing segment's operating income for the year ended December 31, 2005, was $42.0 million.
- In July 2005, we acquired Koch Vesco Holdings, LLC, an entity which owns a 10.2 percent interest in VESCO. VESCO owns a gas processing complex near Venice, Louisiana.

Selected Financial and Operating Information - The following tables set forth certain selected financial and operating information for our Gathering and Processing segment for the periods indicated.

	Years Ended December 31,		
Financial Results	**2005**	**2004**	**2003**
	(Thousands of dollars)		
Natural gas liquids and condensate sales	**$ 671,865**	$ 575,537	$ 449,294
Gas sales	**877,049**	669,956	640,499
Gathering, compression, dehydration and processing fees and other revenues	**99,660**	93,491	91,259
Cost of sales and fuel	**1,361,308**	1,071,954	982,753
Net margin	**287,266**	267,030	198,299
Operating costs	**123,385**	118,090	112,822
Depreciation, depletion and amortization	**32,649**	32,744	29,273
Gain on sale of assets	**264,207**	-	-
Operating income	**$ 395,439**	$ 116,196	$ 56,204
Other income (expense), net	**$ (7,373)**	$ 486	$ (108)
Cumulative effect of a change in accounting principle, net of tax	**$ -**	**$ -**	$ (1,375)

	Years Ended December 31,		
Operating Information	**2005**	**2004**	**2003**
Total gas gathered *(MMMBtu/d)*	**1,077**	1,099	1,171
Total gas processed *(MMMBtu/d)*	**1,117**	1,172	1,209
Natural gas liquids sales *(MBbls/d)*	**49**	51	49
Natural gas liquids produced *(MBbls/d)*	**59**	62	59
Gas sales *(MMMBtu/d)*	**329**	328	330
Capital expenditures *(Thousands of dollars)*	**$ 28,316**	$ 23,067	$20,444
Average Conway OPIS composite NGL price *($/gal)* (based on our NGL product mix)	**$ 0.89**	$ 0.72	$ 0.59
Average NYMEX crude oil price *($/Bbl)*	**$ 55.76**	$ 41.34	$ 30.98
Average realized condensate price *($/Bbl)*	**$ 52.69**	$ 38.17	$ 28.68
Average natural gas price *($/MMBtu)* (mid-continent region)	**$ 7.30**	$ 5.54	$ 5.06
Gross processing spread *($/MMBtu)*	**$ 2.77**	$ 2.47	$ 1.36

	Years Ended December 31,	
	2005	**2004**
Keep whole:		
NGL shrink *(MMBtu/d)*	**61,558**	80,700
Plant fuel *(MMBtu/d)*	**8,734**	9,670
Condensate shrink *(MMBtu/d)*	**4,682**	5,930
Condensate sales *(Bbls/d)*	**961**	1,217
Percentage of total net margin	**13.5%**	19.0%
Percentage of Proceeds:		
Wellhead purchases *(MMBtu/d)*	**184,294**	219,800
NGL sales *(Bbls/d)*	**6,634**	6,975
Residue sales *(MMBtu/d)*	**24,835**	24,270
Condensate sales *(Bbls/d)*	**1,644**	1,705
Percentage of total net margin	**61.6%**	55.0%
Fee:		
Wellhead volumes *(MMBtu/d)*	**1,076,518**	1,120,500
Average rate *($/MMBtu)*	**$ 0.18**	$ 0.17
Percentage of total net margin	**24.8%**	26.0%

Operating Results - The financial and operating results set forth in the table above have been restated to reflect the transfer of the natural gas liquids marketing business that was previously included in our Gathering and Processing segment to our new Natural Gas Liquids segment.

The change in net margin for 2005, compared with 2004, is primarily due to:

- an increase of $18.8 million attributable to our keep whole contracts, net of hedging, due primarily to an increase in our gross processing spread,
- an increase of $8.0 million due to higher natural gas and NGL prices on our POP contracts, net of hedging, and
- a decrease of $6.5 million due to the sale of certain natural gas gathering and processing assets located in Texas in December 2005.

The gross processing spread for 2005, which is the relative difference in economic value between NGLs and natural gas on a Btu basis, was higher than the previous five-year average of $1.78. The gross processing spread in 2005 was $2.77 per MMBtu versus $2.47 per MMBtu in 2004. Improved contractual terms for gas gathering and processing, resulting from our continued efforts to renegotiate under-performing gas purchase, gas processing and gas gathering contracts, continue to positively impact net margin.

The increase in operating costs for 2005 is primarily due to an increase of $1.5 million in materials, supplies and utilities related to compressor utilization and maintenance, and a $1.1 million increase from the higher cost of chemicals. The remaining increase is associated with higher employee-related costs.

Operating income for 2005 includes a $264.2 million gain on the sale of our natural gas gathering and processing assets located in Texas to a subsidiary of Eagle Rock Energy, Inc. in December 2005. See Note B of Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional information.

The decrease in other income (expense) for 2005 is primarily due to an impairment of $5.9 million recognized in the fourth quarter of 2005 related to a 50 percent equity investment in an Oklahoma gas plant which we do not operate and a $1.3 million gain from our 2004 sale of propane distribution assets located in south Texas. The remaining decrease is due to an accrual of a $0.5 million insurance deductible associated with VESCO. The Venice, Louisiana plant suffered damage in August 2005 from Hurricane Katrina. Management expects that insurance payments from our carriers will cover the remaining costs associated with repairing the damage to the facility. The facility is expected to be back in partial service by March 31, 2006.

The increase in capital expenditures for 2005 is primarily related to well connects and additional compression expenditures.

The increase in net margin in 2004, compared with 2003, is primarily due to:

- an increase of $16.8 million due to favorable commodity pricing for natural gas and NGL products on our POP contracts,
- an increase of $50.2 million attributable to our keep whole contracts due primarily to an increase in our gross processing spread, and
- an increase of $1.8 million due to higher NGL production and sales, partially offset by reduced natural gas sales.

The increase in operating costs in 2004, compared with 2003, is primarily attributable to approximately $3.6 million of charges associated with various contractual dispute settlements in 2004. Employee costs were also $2.7 million higher in 2004 compared with 2003.

Depreciation, depletion and amortization increased in 2004 compared with 2003 primarily due to shorter depreciation lives on certain capital expenditures, the acquisition of new properties and our normal capital expenditure program.

Risk Management - We use derivative instruments to minimize the risks associated with price volatility. In 2005 and 2004, we used a variety of instruments including physical forward sales, NYMEX natural gas futures, NYMEX crude oil futures, and over-the-counter natural gas and natural gas liquid swaps to hedge the cash flows for the purchases and sales of natural gas, sales of condensate and sales of NGLs produced by our operations. We used physical forward sales and derivative instruments to secure a certain price for natural gas, condensate and NGL products. The keep whole spread is hedged with a combination of derivative instruments for the purchase of natural gas and derivative instruments and physical forward sales for NGLs. The realized financial impact of the derivative transactions is included in our operating income in the period that the physical transaction occurs.

The following table sets forth the 2006 hedging information for our Gathering and Processing segment for the periods indicated.

	Three Months Ending March 31, 2006		Year Ending December 31, 2006	
Product	**Volumes Hedged**	**Average Price**	**Volumes Hedged**	**Average Price**
Percent of Proceeds:				
Condensate (a)	75 MBbls	$52.00-60.00/Bbl	300 MBbls	$52.00-60.00/Bbl
Natural gas (a)	0.5 Bcf	$6.15-11.00/MMBtu	1.9 Bcf	$6.15-11.00/MMBtu
Natural gas (b)	0.5 Bcf	$9.76/MMBtu	0.5 Bcf	$9.76/MMBtu

(a) - Hedged with NYMEX-based costless collars.

(b) - Hedged with NYMEX futures and basis swaps.

We continue to evaluate market conditions for the remainder of 2006 to take advantage of favorable pricing opportunities for our company-owned production associated with the POP contracts, as well as our keep whole quantities.

See Item 7A, Quantitative and Qualitative Disclosures About Market Risk and Note D of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Natural Gas Liquids

Overview - Our Natural Gas Liquids segment gathers, stores, fractionates and treats raw NGLs produced from gas processing plants located in Oklahoma, Kansas and the Texas panhandle. We connect the NGL production basins in Oklahoma, Kansas and the Texas panhandle with the key NGL market centers in Conway, Kansas and Mont Belvieu, Texas.

Most natural gas produced at the wellhead contains a mixture of NGL components such as ethane, propane, iso-butane, normal butane and natural gasoline. Natural gas processing plants remove the NGLs from the natural gas stream to realize the higher economic value of the NGLs and to meet natural gas pipeline quality specifications, which limit NGLs in the natural gas stream due to liquid and Btu content.

The NGLs that are separated from the natural gas stream at the natural gas processing plants remain in a mixed, raw form until they are gathered, primarily by pipeline, and delivered to our fractionators. A fractionator, by applying heat and pressure, separates each NGL component into marketable products, such as ethane/propane mix, propane, iso-butane, normal butane and natural gasoline (collectively, NGL products). These NGL products are then stored and/or distributed to petrochemical, heating and motor gasoline manufacturers.

Acquisition - The following acquisition is discussed beginning on page 25.

- In July 2005, we acquired natural gas liquids businesses from Koch.

Selected Financial and Operating Information - The following tables set forth certain selected financial and operating information for our Natural Gas Liquids segment for the periods indicated.

	Years Ended December 31,		
Financial Results	**2005**	**2004**	**2003**
	(Thousands of dollars)		
Natural gas liquids and condensate sales	**$ 2,361,488**	$ 1,243,347	$ 1,018,622
Storage and fractionation revenues	**98,887**	13,151	4,995
Cost of sales	**2,372,486**	1,232,082	1,007,779
Net margin	**87,889**	24,416	15,838
Operating costs	**33,460**	9,462	9,281
Depreciation, depletion and amortization	**11,060**	119	59
Operating income	**$ 43,369**	$ 14,835	$ 6,498
Other income (expense), net	**$ 231**	$ (148)	$ (86)

		Years Ended December 31,		
Operating Information		**2005**	**2004**	**2003**
Natural gas liquids gathered *(MBbls/d)*	(a)	**191**	-	-
Natural gas liquids sales *(MBbls/d)*		**207**	109	112
Natural gas liquids fractionated *(MBbls/d)*	(a)	**292**	-	-
Capital expenditures *(Thousands of dollars)*		**$ 12,220**	$ 9,264	$ 154

(a) Data presented for 2005 represents the per day results of operations from July 1, 2005.

Operating Results - The results of operations for 2004 and 2003 set forth above are related to the natural gas liquids marketing business that was previously included in our Gathering and Processing segment. The increases for 2005 are primarily related to the natural gas liquids assets acquired in July 2005. The increases associated with the acquisition for 2005 include:

- an increase in net margin of $57.4 million,
- an increase in operating costs of $22.2 million, and
- an increase in depreciation, depletion and amortization of $10.3 million.

The remaining net margin increase for 2005 is primarily related to increased storage margins of $4.8 million from restructured storage contracts.

Increased storage regulatory compliance costs resulted in an additional $1.7 million in operating costs for 2005, compared with 2004.

The increase in net margins for the year ended December 31, 2004, compared with the same period in 2003, was primarily due to increased storage margins and higher NGL prices. Storage margins increased $10.2 million primarily from the addition of storage and pipeline assets located in Conway, Kansas.

Pipelines and Storage

Overview - Our Pipelines and Storage segment, formerly Transportation and Storage, operates our intrastate natural gas transmission pipelines, natural gas storage, regulated natural gas liquids gathering and distribution pipelines, and non-processable natural gas gathering facilities. We also provide interstate natural gas transportation and storage service under Section 311(a) of the NGPA.

In Oklahoma, we have access to the major natural gas producing areas, allowing for natural gas and natural gas liquids to be moved throughout the state. We have access to the major natural gas producing area in south central Kansas. In Texas, we are connected to the major natural gas producing areas in the Texas panhandle and the Permian Basin, providing for natural gas to be moved to the Waha Hub, where other pipelines may be accessed for transportation east to the Houston Ship Channel market and west to the California market. Our natural gas liquids gathering connections provide for raw NGLs gathered in Oklahoma, Kansas and the Texas panhandle to be delivered to our fractionation facilities in these states and to our natural gas liquids distribution pipelines which allows for access to the two main NGL market centers in Conway, Kansas and Mont Belvieu, Texas.

Acquisitions and Divestitures - The following acquisitions and divestitures are described beginning on page 25.

- In December 2005, we sold approximately ten miles of non-contiguous, natural gas gathering pipelines in Texas.
- In July 2005, we acquired the FERC regulated assets that were part of the acquisition from Koch.
- In January 2003, we acquired natural gas transmission assets as part of the purchase of our Texas assets.

Selected Financial and Operating Information - The following tables set forth certain selected financial and operating information for our Pipelines and Storage segment for the periods indicated.

	Years Ended December 31,		
Financial Results	**2005**	**2004**	**2003**
	(Thousands of dollars)		
Transportation and gathering revenues	**$ 151,490**	$ 101,950	$ 102,812
Storage revenues	**51,562**	45,791	42,086
Gas sales and other revenues	**22,598**	19,694	16,401
Cost of sales and fuel	**54,036**	40,887	47,637
Net margin	**171,614**	126,548	113,662
Operating costs	**63,326**	49,414	46,186
Depreciation, depletion and amortization	**23,702**	17,349	16,694
Operating income	**$ 84,586**	$ 59,785	$ 50,782
Other income (expense), net	**$ (657)**	$ 2,835	$ 1,495
Cumulative effect of a change in accounting principle, net of tax	**$ -**	$ -	$ (645)

		Years Ended December 31,		
Operating Information		**2005**	**2004**	**2003**
Natural gas transported *(MMcf)*		**486,635**	432,844	449,261
Natural gas liquids transported *(MBbls/d)*	(a)	**187**	-	-
Natural gas liquids gathered *(MBbls/d)*	(a)	**53**	-	-
Capital expenditures *(Thousands of dollars)*		**$ 15,719**	$ 12,287	$ 15,234
Average natural gas price (*$/MMBtu*) (mid-continent region)		**$ 7.30**	$ 5.54	$ 5.06

(a) Data presented for 2005 represents the per day results of operations from July 1, 2005.

Operating Results - Net margin, which increased in 2005, compared with 2004, was affected by:

- an increase of $26.4 million related to revenues on natural gas liquids gathering and distribution pipelines acquired in July 2005,
- an increase of $20.5 million in natural gas transport revenues resulting from increased throughput due to favorable weather conditions for transportation, our improved fuel position and significantly higher commodity prices,
- an increase of $5.8 million related to increased storage revenues from renegotiated contracts, improved fuel position and higher commodity prices, and
- a decrease of $5.8 million related to lower net margins on equity natural gas inventory sales.

The increase in operating costs in 2005, compared with 2004, is due to:

- an increase of $11.5 million for natural gas liquids gathering and distribution pipelines acquired in July 2005,
- increased outside services costs of $1.7 million primarily driven by regulatory compliance requirements, and
- higher employee costs offset in part by lower litigation costs as compared with 2004.

The increase in depreciation, depletion and amortization of approximately $6.4 million for 2005 is primarily related to the newly-acquired natural gas liquids pipelines.

The decrease in other income (expense), net, for 2005 is due in part to the gain on the sale of certain assets in 2004. Also impacting 2005 is a $2.6 million impairment charge related to one of our gas gathering partnerships that may terminate in early 2006, partially offset by a $0.9 million gain on sale of non-contiguous, natural gas gathering pipelines in Texas.

Net margin, which increased in 2004, compared with 2003, was affected by:
- an increase of $8.9 million related to the sale of operational gas inventory in December 2004,
- increased storage revenues of $2.4 million due to spot storage transactions resulting from the weather and favorable forward pricing in 2004,
- decreased cost of sales and fuel of $1.7 million primarily related to lower transportation volumes partially offset by increased fuel consumed and higher fuel prices, resulting from increased storage activity, and
- decreased volumes transported as a result of milder and wetter weather reducing irrigation, power generation and heating demands.

The increase in operating costs in 2004, compared with 2003, is due to:
- increased regulatory and pipeline integrity compliance costs of $2.9 million, and
- higher employee costs and legal costs for settled litigation.

In 2004, other income (expense), net includes the gain on the sale of the Texas assets of $6.9 million, which is partially offset by litigation costs.

Energy Services

Overview - Our Energy Services segment's primary focus is to create value for our customers by delivering physical products and risk management services through our network of contracted gas supply, transportation and storage capacity. These services include meeting our customers' baseload, swing and peaking natural gas commodity requirements on a year-round basis. To provide these bundled services, we lease storage and transportation capacity. Our total storage capacity under lease is 86 Bcf, with maximum withdrawal capability of 2.3 Bcf/d and maximum injection capability of 1.6 Bcf/d. Our current transportation capacity is 1.9 Bcf/d. The contracted storage and transportation capacity connects the major supply and demand centers throughout the United States and into Canada. With these contracted assets, our business strategies include identifying, developing and delivering specialized services and products for premium value to our customers, which are primarily LDCs, electric utilities, and commercial and industrial end users. Also, our storage and transportation capacity allows us opportunities to optimize these positions through our application of market knowledge and risk management skills.

Selected Financial and Operating Information - The following tables set forth certain selected financial and operating information for our Energy Services segment for the periods indicated. In the third quarter of 2005, we made the decision to sell our Spring Creek power plant, located in central Oklahoma, and exit the power generation business. In October 2005, we concluded that our Spring Creek power plant had been impaired and recorded an impairment expense of $52.2 million. These assets were held for sale at December 31, 2005, and, accordingly, this component of our business is accounted for as discontinued operations, in accordance with Statement 144. The discontinued operations are excluded from the financial and operating results below. For additional information, see discussion of discontinued operations on page 43.

	Years Ended December 31,		
Financial Results	**2005**	**2004**	**2003**
	(Thousands of dollars)		
Energy and power revenues	**$ 8,345,091**	$ 2,720,629	$ 6,462
Energy trading revenues, net	**12,680**	113,814	229,782
Other revenues	**980**	849	961
Cost of sales and fuel	**8,152,391**	2,661,286	8,508
Net margin	**206,360**	174,006	228,697
Operating costs	**38,598**	33,261	32,226
Depreciation, depletion and amortization	**2,071**	1,554	1,612
Operating income	**$ 165,691**	$ 139,191	$ 194,859
Other income (expense), net	**$ (8,635)**	$ (6,920)	$ (9,272)
Cumulative effect of a change in accounting principle, net of tax	**$ -**	$ -	$ (141,982)

Operating Information	Years Ended December 31, 2005	2004	2003
Natural gas marketed *(Bcf)*	**1,191**	1,073	1,012
Natural gas gross margin *($/Mcf)*	**$ 0.14**	$ 0.14	$ 0.17
Physically settled volumes *(Bcf)*	**2,387**	2,157	2,028
Capital expenditures *(Thousands of dollars)*	**$ 159**	$ 1,806	$ 555

Operating Results - Net margins increased for 2005, compared with 2004, primarily due to:
- an increase of $41.9 million in transportation margins, net of economic hedges, due to improved natural gas basis differentials primarily in the fourth quarter of 2005 associated with certain capacity held in the Mid-Continent region,
- an increase of $22.6 million in wholesale physical marketing margins resulting from favorable natural gas price volatility primarily in the fourth quarter of 2005, and
- an increase of $6.8 million in power trading margins related to improved Electric Reliability Council of Texas (ERCOT) market heat-rates attributable to a 13.2 percent increase in cooling degree days compared to normal and a 10.0 percent increase in cooling days compared with the same period in 2004.

These increases in net margin were partially offset by:
- a net decrease of $18.3 million in storage margins from cash flow hedge ineffectiveness primarily related to natural gas basis movements attributable to anticipated storage withdrawals from the 2006/2007 heating season,
- a decrease of $18.4 million resulting from less favorable price movements in 2005 related to our natural gas fixed price activities, and
- a decrease of $2.2 million in retail activities related to reduced physical margins.

The increase in operating costs in 2005, compared with 2004, is primarily due to increased employee-related costs of $1.3 million and increased legal costs of $2.9 million.

Our natural gas in storage at December 31, 2005, was 62.1 Bcf compared with 70.6 Bcf at December 31, 2004. At December 31, 2005, our total natural gas storage capacity under lease was 86 Bcf compared with 84 Bcf at December 31, 2004.

Net margin was negatively affected in 2004, compared with 2003, primarily due to:
- a decrease of $43.7 million in margins from marketing and seasonal natural gas sales from storage resulting from lower inter-regional basis spreads early in 2004,
- a decrease of $35.9 million attributable to lower natural gas price volatility and the impact it had on our trading margins, and
- a decrease of $4.7 million resulting from weaker spark spreads in ERCOT.

These decreases in net margin were partially offset by:
- increased revenues of $9.5 million in reservation fees received for natural gas peaking services and
- increased revenues of $20.5 million related to the seasonal spread, which resulted in increased sales volumes as we recycled natural gas in storage during the fourth quarter of 2004.

Natural gas volumes marketed increased for 2005, compared with 2004, due to our expanded Canadian operations, additional long-term transportation contracts and opportunities to sell into supply-constrained markets. Natural gas volumes increased in 2004, compared with 2003, due to our Canadian operations and higher natural gas storage inventory levels at the beginning of 2004, which shifted purchased volumes from storage injections to regional sales.

The acquisition of natural gas storage capacity has become more competitive as a result of new entrants from the financial services sector, the increase in the spread between summer and winter natural gas prices, and natural gas price volatility. The increased demand for storage capacity has resulted in an increase in both the cost of leasing storage capacity and the required term of the lease. Longer terms for our storage capacity leases could result in significant increases in our contractual commitments.

At the beginning of the third quarter of 2004, we completed a reorganization of our Energy Services segment and renewed our focus on our physical marketing and storage business. We separated the management and operations of our wholesale marketing, retail marketing and trading activities and began accounting separately for the different types of revenue earned from these activities. Prior to the third quarter of 2004, we managed our Energy Services segment on an integrated basis and presented all energy trading activity on a net basis.

Concurrent with this reorganization, we evaluated the accounting treatment related to the presentation of revenues from the different types of activities to determine which amounts should be reported on a gross or net basis under the guidance in EITF Issue No. 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not "Held for Trading Purposes" as Defined in EITF Issue No. 02-3" (EITF 03-11). For derivative instruments considered held for trading purposes that result in physical delivery, the indicators in EITF Issue No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" were used to determine the proper treatment. These activities and all financially settled derivative contracts will continue to be reported on a net basis.

For derivative instruments that are not considered "held for trading purposes" and that result in physical delivery, the indicators in EITF 03-11 and EITF Issue No. 99-19, "Reporting Revenue Gross as a Principal versus Net as an Agent" (EITF 99-19) were used to determine the proper treatment. We began accounting for the realized revenues and purchase costs of these contracts that result in physical delivery on a gross basis beginning with the third quarter of 2004. We apply the indicators in EITF 99-19 to determine the appropriate accounting treatment for non-derivative contracts that result in physical delivery. Derivatives that qualify for the normal purchase or sale exception as defined in Statement 133 are also reported on a gross basis. Prior periods have not been adjusted for this change; therefore, comparisons to prior periods may not be meaningful. Reporting of these transactions on a gross basis did not impact operating income but resulted in an increase to revenues and cost of sales and fuel.

The following table shows the margins by activity, beginning with our reorganization on July 1, 2004.

	Year Ended December 31, 2005	**Six Months Ended December 31, 2004**
	(Thousands of dollars)	
Marketing and storage, gross	**$ 350,227**	$ 126,989
Less: Storage and transportation costs	**(174,838)**	(72,661)
Marketing and storage, net	**175,389**	54,328
Retail marketing	**17,526**	8,628
Financial trading	**13,445**	23,221
Net margin	**$ 206,360**	$ 86,177

Marketing and storage activities primarily include physical marketing (purchase and sales) using our firm storage and transportation capacity, including cash flow and fair value hedges and other derivative instruments to manage our risk associated with these activities. The combination of owning supply, controlling strategic assets and risk management services allows us to provide commodity-diverse products and services to our customers such as peaking and load following services. Power activities are also included in the marketing and storage business. Retail marketing includes revenues from providing physical marketing and supply services to residential and small commercial and industrial customers. Financial trading revenues include activities that are generally executed using financially settled derivatives. These activities are normally short term in nature with a focus of capturing short-term price volatility.

Distribution

Overview - Our Distribution segment provides natural gas distribution services to over two million customers in Oklahoma, Kansas and Texas through Oklahoma Natural Gas, Kansas Gas Service and Texas Gas Service, respectively. We serve residential, commercial, industrial and transportation customers in all three states. In addition, our distribution services in Oklahoma and Kansas serve wholesale customers and Texas serves public authority customers.

In September 2005, Hurricane Rita caused significant damage to customers' homes and businesses in the service area of Texas Gas Service located in south Jefferson County and Port Arthur, Texas. Texas Gas Service suffered damage to its Port Arthur service center, meters in south Jefferson County and Port Arthur, Texas, and incurred system natural gas loss. The financial impact will not be material due to insurance coverage that covers property damage, natural gas loss and business interruption.

Acquisition - The following acquisition is described beginning on page 25:

- In January 2003, we acquired our Texas natural gas distribution assets.

Selected Financial Information - The following table sets forth certain selected financial and operating information for our Distribution segment for the periods indicated.

	Years Ended December 31,		
Financial Results	**2005**	**2004**	**2003**
	(Thousands of dollars)		
Gas sales	**$ 2,094,126**	$ 1,816,697	$ 1,640,323
Transportation revenues	**94,160**	82,006	75,322
Cost of gas	**1,628,507**	1,367,186	1,213,811
Gross margin	**559,779**	531,517	501,834
Other revenues	**27,921**	25,799	24,415
Net margin	**587,700**	557,316	526,249
Operating costs	**360,351**	341,651	312,814
Depreciation, depletion and amortization	**113,437**	105,438	95,654
Operating income	**$ 113,912**	$ 110,227	$ 117,781
Other income (expense), net	**$ (1,081)**	$ 1,375	$ (278)

Operating Results - Net margin increased for 2005, compared with 2004, due to:

- an increase of $28.2 million resulting from the implementation of new rate schedules in Oklahoma,
- an increase of $2.3 million resulting from increased wholesale transactions in Kansas,
- an increase of $4.9 million due to the ad valorem tax recovery rider, which is offset in amortization expense, and
- an offsetting decrease of $5.2 million in customer sales volumes due to warmer weather.

Operating costs increased for 2005, compared with 2004, due to:

- an increase of $12.5 million in labor and employee benefit costs,
- an increase of $2.0 million in bad debt expense,
- an increase of $3.2 million due to equipment leasing costs, higher vehicle fuel costs, and an insurance deductible related to Hurricane Rita.

Depreciation, depletion and amortization increased for 2005 primarily due to:

- a $2.9 million charge related to the replacement of our field customer service system in Texas,
- a $3.5 million depreciation expense related to our investment in property, plant and equipment,
- a $4.9 million amortization of the ad valorem tax recovery rider in Kansas, and
- an offsetting decrease of $3.2 million in pension expense amortization in Oklahoma which expired in 2004.

Net margin increased in 2004, compared with 2003, primarily due to:

- the implementation of new rate schedules in Kansas and Oklahoma, which added $22.0 million and $14.5 million, respectively, and
- certain commercial and industrial customers in Oklahoma who converted to transportation rates as a result of lower volume thresholds to qualify for transportation rates, which increased transportation revenue by $1.5 million and decreased gross margin by an equivalent amount.

These increases in net margin were partially offset by:

- decreased revenues of $4.9 million due to the impact of reduced customer usage in Kansas and Oklahoma primarily attributable to the impact of warmer weather on customers not subject to weather normalization, and
- increased line loss expense of $2.4 million, net of rider recoveries, in Oklahoma.

Operating costs, which increased in 2004, compared with 2003, were impacted by:

- increased information technology costs of $7.6 million, primarily associated with our customer service system, and
- increased employee costs of $18.9 million.

Depreciation, depletion and amortization expense increased for 2004, compared with 2003, due to:

- amortization expense of $5.7 million related to the new rate schedules in Kansas and Oklahoma, and
- depreciation expense of $4.1 million related to our investment in property, plant and equipment.

Selected Operating Data - The following tables set forth certain selected financial and operating information for our Distribution segment for the periods indicated.

	Years Ended December 31,		
Operating Information	**2005**	**2004**	**2003**
Average number of customers	**2,018,900**	2,008,835	1,990,757
Customers per employee	**689**	664	652
Capital expenditures (*Thousands of dollars)*	**$ 143,765**	$ 142,515	$ 153,405

	Years Ended December 31,		
Volumes *(MMcf)*	**2005**	**2004**	**2003**
Gas sales			
Residential	**122,010**	123,388	126,998
Commercial	**39,294**	41,984	45,054
Industrial	**2,432**	2,513	3,442
Wholesale	**33,521**	32,265	29,823
Public Authority	**2,559**	2,748	2,645
Total volumes sold	**199,816**	202,898	207,962
Transportation	**252,180**	239,914	231,425
Total volumes delivered	**451,996**	442,812	439,387

	Years Ended December 31,		
Margin	**2005**	**2004**	**2003**
Gas sales		*(Thousands of dollars)*	
Residential	**$ 363,265**	$ 344,486	$ 325,540
Commercial	**89,828**	92,793	89,581
Industrial	**2,785**	3,496	3,183
Wholesale	**6,672**	5,347	5,033
Public Authority	**3,069**	3,389	3,175
Gross margin on gas sales	**465,619**	449,511	426,512
Transportation	**94,160**	82,006	75,322
Gross margin	**$ 559,779**	$ 531,517	$ 501,834

Residential, commercial and industrial volumes decreased in 2005, compared with 2004, and in 2004, compared with 2003, due to:

- warmer weather, which primarily affects residential and commercial customers, and
- commercial customers migrating to new transportation rates as a result of lower minimum transport thresholds in Oklahoma.

Wholesale sales represent contracted natural gas volumes that exceed the needs of our residential, commercial and industrial customer base and are available for sale to other parties. Wholesale volumes increased for 2005, as fewer volumes were required to meet the needs of residential, commercial and industrial customers, resulting in additional volume being available for sale to other parties.

Public authority natural gas volumes, which remained relatively flat in 2005 compared with the prior years, reflect volumes used by state agencies and school districts serviced by Texas Gas Service.

Transportation volumes increased for 2005 primarily due to commercial and industrial customers of Oklahoma Natural Gas migrating to new transportation rates as a result of lower minimum transport thresholds.

Transportation volumes increased in 2004, compared with 2003, primarily due to:

- the acquisitions of the distribution system at the United States Army's Fort Bliss in El Paso, Texas, and a pipeline system that extends through the Rio Grande Valley region in Texas,
- the continued migration of commercial and industrial customers to new transportation rates as a result of lower minimum transport thresholds in Oklahoma, and

- the marketing effort by Oklahoma Natural Gas to add small usage transport customers.

Capital Expenditures - Our capital expenditure program includes expenditures for extending service to new areas, modifying customer service lines, increasing system capabilities, general replacements and improvements. It is our practice to maintain and periodically upgrade facilities to assure safe, reliable and efficient operations. Our capital expenditure program included $38.6 million, $35.0 million and $33.5 million for new business development in 2005, 2004 and 2003, respectively.

Oklahoma Regulatory Initiatives - On October 4, 2005, the OCC issued a final order on our application for a rate increase by Oklahoma Natural Gas. The OCC unanimously approved an annual rate increase of $57.5 million. The Commission's administrative law judge had recommended an increase in annual revenues of approximately $58.0 million in July 2005. Oklahoma Natural Gas implemented new rates, subject to refund, on July 28, 2005, based on the judge's report. Oklahoma Natural Gas and the Attorney General both filed appeals from the administrative law judge's recommendation. All parties ultimately reached a settlement of the appeals, which was approved by the OCC in its final order.

On January 30, 2004, the OCC issued an order allowing Oklahoma Natural Gas annual rate relief of $17.7 million in order to recover expenses related to its investment in service lines and cathodic protection, an increased level of uncollectible revenues, and a return on Oklahoma Natural Gas' service lines and investment in natural gas in storage. The OCC's order also approved a modified distribution main extension policy and authorized Oklahoma Natural Gas to defer homeland security costs. The order authorized the new rates to be in effect for a maximum of 18 months and categorized $10.7 million of the annual additional revenues as interim and subject to refund until a final determination at Oklahoma Natural Gas' next general rate case. This interim relief expired on July 27, 2005, and was replaced by the rate increase of $57.5 million approved on October 4, 2005. As the final rate increase exceeded the interim revenues that were subject to refund, no refund obligation was incurred associated with this rate increase.

A Joint Stipulation approved by the OCC on May 16, 2002, settled a number of outstanding Oklahoma Natural Gas cases pending before the OCC. The major cases settled were the OCC's inquiry into our gas cost procurement practices during the winter of 2000/2001, an application seeking relief from improper and excessive purchased gas costs, and enforcement action against Oklahoma Natural Gas, our subsidiaries and affiliated companies. In addition, all of the open inquiries related to the annual audits of Oklahoma Natural Gas' fuel adjustment clause for 1996 to 2000 were closed as a result of this Stipulation.

The Stipulation had a $33.7 million value to Oklahoma Natural Gas customers that was realized over a three-year period. In July 2002, immediate cash savings were provided to all Oklahoma Natural Gas customers in the form of billing credits totaling approximately $9.1 million. Oklahoma Natural Gas replaced certain natural gas contracts, which reduced natural gas costs by approximately $13.8 million, due to avoided reservation fees between April 2003 and October 2005. Storage value of $2.0 million was generated on behalf of customers. As a part of the final rate order issued on October 4, 2005, Oklahoma Natural Gas was authorized to net $1.8 million in under-recovered revenues authorized for recovery under the OCC's January 30, 2004 rate order against its final December 2005 billing credit obligation. In December 2005, a final billing credit of $6.9 million was made to customers.

Kansas Regulatory Initiatives - On September 17, 2003, the KCC issued an order approving $45 million in rate relief pursuant to the stipulated settlement agreement with Kansas Gas Service. The order settled the rate case filed by Kansas Gas Service in January 2003 and allowed Kansas Gas Service to begin operating under the new rate schedules effective September 22, 2003. After amortization of previously deferred costs, annual operating income increased by approximately $25.8 million.

On June 24, 2005, the KCC issued an order authorizing the inclusion of the natural gas cost component of uncollectible customer accounts in the Cost of Gas Rider. Kansas Gas Service began deferring the natural gas cost component of uncollectible accounts in July 2005 for subsequent recovery through the Cost of Gas Rider.

The KCC staff has made several rule recommendations to segregate public utility operations within diversified utility companies or holding company business structures. If adopted, the KCC staff recommendations could result in changes to our business practices.

Texas Regulatory Initiatives - On November 23, 2005, Texas Gas Service filed requests for rate increases in its Port Arthur and north Texas services areas for $2.4 million and $1.1 million, respectively. The municipalities have suspended the proposed rates for 90 days in order to conduct further review of the filings.

On November 12, 2003, Texas Gas Service filed an appeal with the RRC based on the denial of proposed rate filing by the cities of Port Neches, Nederland and Groves, Texas. In July 2004, the RRC approved approximately $0.9 million in annual revenue relief. The interim rates were implemented in May 2003. On October 7, 2004, Texas Gas Service filed a petition in the District Court of Travis County, Texas seeking judicial review of certain of the ratemaking decisions contained in the RRC's final order. On October 26, 2005, the district court upheld the RRC final order. On November 23, 2005, Texas Gas Service and the cities of Port Neches, Nederland and Groves, Texas appealed the decision of the District Court to the Third District Court of Appeals. A decision is expected on this appeal in 2006.

General - Certain costs to be recovered through the ratemaking process have been recorded as regulatory assets in accordance with Statement 71. Should recovery cease due to regulatory actions, certain of these assets may no longer meet the criteria of Statement 71 and, accordingly, a write-off of regulatory assets and stranded costs may be required.

Discontinued Operations

Overview - In September 2005, we completed the sale of our Production segment to TXOK Acquisition, Inc. for $645 million, before adjustments, and recognized a pre-tax gain on the sale of approximately $240.3 million. The gain reflects the cash received less adjustments, selling expenses and the net book value of the assets sold. The proceeds from the sale were used to reduce debt. Our Board of Directors had approved the potential sale in July 2005, which resulted in our Production segment being classified as held for sale beginning July 1, 2005. In accordance with Statement 144, we did not record any depreciation, depletion or amortization for our Production segment while it was classified as held for sale.

Additionally, in the third quarter of 2005, we made the decision to sell our Spring Creek power plant and exit the power generation business. We entered into an agreement to sell our Spring Creek power plant to Westar for $53 million. The transaction requires FERC approval and is expected to be completed in 2006. The 300-megawatt gas-fired merchant power plant was built in 2001 to supply electrical power during peak periods using gas-powered turbine generators. The proceeds from this sale will be used to purchase other assets, repurchase ONEOK shares or retire debt.

In January 2003, we sold approximately 70 percent of the natural gas and crude oil producing properties of our Production segment for an adjusted cash price of $294 million. The properties sold were in Oklahoma, Kansas and Texas. We recognized a pretax gain of approximately $61.2 million in 2003 related to this sale. The gain reflects the cash received less adjustments, selling expenses and the net book value of the assets sold.

These components of our business are accounted for as discontinued operations in accordance with Statement 144. Accordingly, amounts in our financial statements and related notes for all periods shown relating to our Production segment and our power generation business are reflected as discontinued operations. The sale of our Production segment and the pending sale of our power generation business are in line with our business strategy to sell assets when deemed less strategic or as other conditions warrant.

Selected Financial Information - The amounts of revenue, costs and income taxes reported in discontinued operations are as follows.

	Years Ended December 31,		
	2005	**2004**	**2003**
	(Thousands of dollars)		
Operating revenues	**$ 135,213**	$ 202,552	$ 136,271
Cost of sales and fuel	**38,398**	95,524	76,870
Net margin	**96,815**	107,028	59,401
Impairment expense	**52,226**	-	-
Operating costs	**24,302**	29,997	19,270
Depreciation, depletion and amortization	**17,919**	30,673	18,103
Operating income	**2,368**	46,358	22,028
Other income (expense), net	**252**	60	10
Interest expense	**12,588**	16,167	5,953
Income taxes	**(3,788)**	12,746	5,900
Income (loss) from operations of discontinued components, net	**$ (6,180)**	$ 17,505	$ 10,185
Gain on sale of discontinued components, net of tax of $90.7 million, $0 million and $21.5 million, respectively	**$ 149,577**	$ -	$ 39,739

LIQUIDITY AND CAPITAL RESOURCES

General - Part of our strategy is to grow through acquisitions that strengthen and complement our existing assets. We have relied primarily on operating cash flow, borrowings from commercial paper and credit agreements, and issuance of debt and equity in the capital markets for our liquidity and capital resource requirements. We expect to continue to use these sources for liquidity and capital resource needs on both a short- and long-term basis. We have no material guarantees of debt or other similar commitments to unaffiliated parties. During 2005 and 2004, our capital expenditures were financed through operating cash flows and short and long-term debt. Capital expenditures for 2005 were $250 million, compared with $264 million in 2004, exclusive of acquisitions.

Financing - Financing is provided through our commercial paper program and long-term debt. We also have a credit agreement, as discussed below, which is used as a back-up for the commercial paper program. Other options to obtain financing include, but are not limited to, issuance of equity, issuance of mandatory convertible debt securities, issuance of trust preferred securities by ONEOK Capital Trust I or ONEOK Capital Trust II, asset securitization and sale/leaseback of facilities.

The total amount of short-term borrowings authorized by our Board of Directors is $2.5 billion. At December 31, 2005, we had $641.5 million in commercial paper outstanding, $900.0 million drawn on our short-term bridge financing agreement, $178.7 million in letters of credit issued and approximately $7.9 million in cash and temporary investments. We also had $2.0 billion of long-term debt outstanding, including current maturities. As of December 31, 2005, we could have issued $1.5 billion of additional debt under the most restrictive provisions contained in our various borrowing agreements.

Both the five-year credit agreement, which matures in 2009, and short-term bridge financing agreement contain customary affirmative and negative covenants, including covenants relating to liens, investments, fundamental changes in our business, changes in the nature of our business, transactions with affiliates, the use of proceeds, a limit on our debt-to-capital ratio, a limit on investments in master limited partnerships and a covenant that prevents us from restricting our subsidiaries' ability to pay dividends to ONEOK, Inc. In 2005, we amended the five-year credit and the short-term bridge financing agreements to change the definition of Consolidated Net Worth to eliminate the effect of gains and losses recorded in accumulated other comprehensive income (loss) as a result of certain commodity hedging agreements. At December 31, 2005, we were in compliance with all covenants.

Currently, we have $48.2 million available under one of our shelf registration statements on Form S-3, for the issuance and sale of shares of our common stock, debt securities, preferred stock, stock purchase contracts and stock purchase units.

<u>Short-term Bridge Financing Agreement</u> - In June 2005, we entered into a $1.0 billion short-term bridge financing agreement. The interest rate is based, at our election, on either (i) the higher of prime or one-half of one percent above the Federal Funds

Rate, which is the rate that banks charge each other for the overnight borrowing of funds, or (ii) the Eurodollar rate plus a set number of basis points based on our current long-term unsecured debt ratings by Moody's and S&P.

On July 1, 2005, we borrowed $1.0 billion under the short-term bridge financing agreement to assist in financing the acquisition of assets from Koch. See Note B for additional information about this acquisition. We funded the remaining acquisition cost through our commercial paper program. We anticipate permanent financing of the acquisition to come from a combination of proceeds from the sale of assets, such as our Production segment and our Spring Creek power plant, proceeds from the February 2006 settlement of the purchase contracts that were part of our mandatory convertible equity units, and free cash flow. At December 31, 2005, we had lowered the balance of outstanding indebtedness under the bridge financing agreement to $900.0 million. The reduction in indebtedness under our short-term bridge financing agreement is a result of a required prepayment due to the sale of our Production segment. At our option, we paid $200.0 million on February 3, 2006. We paid an additional $403.0 million as a required prepayment on February 16, 2006, from the settlement of our equity units. The remaining balance of $297.0 million is required to be paid by March 31, 2006.

In November 2005, we amended the short-term bridge financing agreement to remove the requirement to prepay the loan with the net cash proceeds received from the disposition of the natural gas gathering and processing assets located in Texas, provided that we prepay our 7.75 percent $300.0 million long-term debt due in August 2006 in full, which we did in December 2005. See further discussion below under Long-term Debt.

<u>Five-year Credit Agreement</u> - In July 2005, we amended our 2004 $1.0 billion five-year credit agreement to increase the limit on our debt-to-capital ratio from 67.5 percent debt to 70.0 percent debt for the period from July 25, 2005, to February 28, 2006. Beginning on March 1, 2006, the limit on our debt will return to 67.5 percent of total capital.

In September 2005, we exercised the accordion feature of our 2004 $1.0 billion five-year credit agreement to increase the commitment amounts by $200 million to a total of $1.2 billion. The interest rate payable under this five-year credit agreement is a floating rate calculated in the same manner as the $1.0 billion short-term bridge financing agreement.

<u>Uncommitted Line of Credit</u> - We entered into a credit agreement with KBC Bank NV in April 2004. The agreement gives us access to an uncommitted line of credit for loans and letters of credit up to a maximum principal amount of $10 million. The rate charged on any outstanding amount is the higher of prime or one-half of one percent above the Federal Funds overnight rate, which is the rate that banks charge each other for the overnight borrowing of funds. This agreement remains in effect until canceled by KBC Bank NV or us. This agreement does not contain any covenants more restrictive than those in our $1.2 billion five-year credit agreement.

In December 2005, we amended our $10.0 million agreement with KBC Bank NV to increase the maximum principal amount available under the uncommitted line of credit to $15.0 million. The increased commitment was used to issue a $15.0 million standby letter of credit.

<u>Long-term Debt</u> - In November 2005, we elected to make an early redemption of our 7.75 percent $300.0 million long-term notes with a stated maturity of August 2006. The early redemption occurred in December 2005, for a total payment of $314.4 million. In addition to the principal payment, we were required to pay a make-whole call premium of $5.7 million and accrued interest of $8.7 million. We funded this early redemption with the proceeds from the sale of our natural gas gathering and processing assets located in Texas.

In June 2005, we issued $800 million of notes, comprised of $400 million in 10-year maturities with a coupon of 5.2 percent and $400 million in 30-year maturities with a coupon of 6.0 percent. Proceeds from this debt issuance were used to repay commercial paper borrowings and for general corporate purposes.

In March 2005, $335 million of our long-term debt matured. We funded payment of this debt with working capital and the issuance of commercial paper in the short-term market.

The following table sets forth our capitalization structure for the periods indicated.

	Years Ended December 31,	
	2005	**2004**
Long-term debt	**53%**	54%
Equity	**47%**	46%
Debt (including Notes payable)	**67%**	61%
Equity	**33%**	39%

<u>Equity Units</u> - Both S&P and Moody's consider the equity units we issued in January 2003 to be part equity and part debt. For purposes of computing capitalization ratios, these rating agencies adjust the capitalization structure. S&P considers the equity units to be equal amounts of debt and equity for the first three years, with the effect being to increase shareholders' equity by the same amount as long-term debt, which would result in a capitalization structure of 52 percent equity and 48 percent long-term debt at December 31, 2005. Moody's considers 25 percent of the equity units to be long-term debt and 75 percent to be shareholders' equity, which would result in a capitalization structure of 55 percent equity and 45 percent long-term debt at December 31, 2005.

We had 16.1 million equity units outstanding at December 31, 2005. Each unit consists of two components, an equity purchase contract and a note (see Notes G and I of Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional information). In November 2005, we remarketed the notes with a new coupon of 5.51 percent. The notes continue to have a stated maturity of February 2008. The cash received was put into a treasury portfolio pledged as collateral against the purchase contracts. This action had no effect on our liquidity. On February 16, 2006, we successfully settled 16.1 million equity units to approximately 19.5 million shares of our common stock. Of this amount, 8.3 million shares were issued from treasury stock and approximately 11.2 million shares were newly issued. Holders of the equity units received 1.2119 shares of our common stock for each equity unit they owned. The number of shares that we issued for each stock purchase contract was determined based on our average closing price over the 20-trading day period ending on the third trading day prior to February 16, 2006. With the settlement, we received $402.4 million in cash, which was used to pay down our short-term bridge financing agreement.

Northern Border Partners - On February 14, 2006, we signed agreements to sell certain assets to Northern Border Partners for approximately $3 billion in cash and limited partner units and increase our general partner interest in Northern Border Partners to 100 percent.

We will purchase, through Northern Plains, from an affiliate of TransCanada 17.5 percent of the general partner interest in Northern Border Partners for $40 million, less $10 million for expenses associated with the transfer of operating responsibility of Northern Border Pipeline Company to TransCanada for a net payment of $30 million. After the transactions are completed, we will own approximately 37.0 million limited partner units and 100 percent of the Northern Border Partners' general partner interest, increasing our total interest in Northern Border Partners to 45.7 percent.

With the purchase of 17.5 percent of the general partner interest in Northern Border Partners, we will also transfer our Gathering and Processing segment, Natural Gas Liquids segment, and Pipelines and Storage segment, to Northern Border Partners in transactions valued at approximately $3 billion. We will receive approximately $1.35 billion in cash and approximately 36.5 million limited partner units from Northern Border Partners. The limited partner units and related general partner interest contribution were valued at approximately $1.65 billion at the time of the signing of the transaction. This sale, subject to adjustment, includes the natural gas liquids assets we purchased from Koch in July 2005 for $1.35 billion. We will not recognize a gain on the sale as the transfer of assets will be accounted for at the assets' historical cost. We plan to use cash proceeds to reduce short-term debt, acquire other assets or repurchase our common stock.

The transfer of our Gathering and Processing segment, Pipelines and Storage segment, and Natural Gas Liquids segment will not affect our consolidated net income on our consolidated statements of income, total assets on our consolidated balance sheets or change in cash and cash equivalents on the consolidated statements of cash flows since under EITF 04-5 we were already required to consolidate Northern Border Partners effective January 1, 2006. See Impact of New Accounting Standards in Management's Discussion and Analysis of Financial Condition and Results of Operation for additional discussion of EITF 04-5.

The limited partner units we will receive from Northern Border Partners will be a newly created Class B units with the same distribution rights as the outstanding common units, but will have limited voting rights and will be subordinated to the common units with respect to payment of minimum quarterly distributions. Distributions on the Class B units will be prorated from the date of issuance. Northern Border Partners is required to hold a special election for holders of common units within 12 months of issuing the Class B units to approve the conversion of the Class B units into common units and to approve certain amendments to the partnership agreement. The proposed amendments grant voting rights for common units held by the general partner if a vote is held to remove the general partner and require fair market value compensation for the general partner interest if the general partner is removed. If the common unit holders do not approve both the conversion and amendments within 12 months of the issuance of the Class B units, then the amount payable on such Class B units would increase to 115 percent of the distributions paid on the common units and the Class B distribution rights would continue to be subordinated in the manner described above unless and until the conversion described above has been approved. If the common unit holders vote to remove us or our affiliates as the general partner of Northern Border Partners at any time prior to the approval of the conversion and amendment described above, the amount payable on such Class B units would increase to 125 percent of the distributions payable with respect to the common units and the Class B unit distribution rights would continue to be subordinated in the manner described above unless and until the conversion described above has been approved.

These transactions are subject to regulatory approvals and other conditions, including antitrust clearance from the Federal Trade Commission under the Hart-Scott-Rodino Act. We expect these transactions will be completed by April 1, 2006.

Stock Buy Back Program - In January 2005, our Board of Directors authorized a stock buy back program to repurchase up to 7.5 million shares of our common stock currently issued and outstanding. Our Board of Directors extended this program in November 2005, and authorized us to repurchase an additional 7.5 million shares of our common stock currently issued and outstanding. Shares are repurchased from time to time in open market transactions or through privately negotiated transactions at our discretion, subject to market conditions and other factors. The program will terminate in November 2007, unless extended by our Board of Directors. During 2005, we repurchased approximately 7.5 million shares of our common stock pursuant to this program.

Credit Rating - Our credit ratings are currently a “Baa2” (Stable) by Moody’s and a “BBB” (CreditWatch with negative implications) by S&P. In October 2005, Moody’s downgraded us to “Baa2” from “Baa1,” S&P downgraded us to “BBB” from “BBB+” and both removed the negative watch. Subsequently, in February 2006, S&P placed our credit rating on negative watch. Our credit ratings may be affected by a material change in our financial ratios or a material adverse event affecting our business. The most common criteria for assessment of our credit ratings are the debt-to-capital ratio, business risk profile, pretax and after-tax interest coverage, and liquidity. If our credit ratings were downgraded, the interest rates on our commercial paper would increase, resulting in an increase in our cost to borrow funds, and we could potentially lose access to commercial paper borrowings. In the event that we are unable to borrow funds under our commercial paper program and there has not been a material adverse change in our business, we have access to a $1.2 billion five-year credit agreement, which expires September 16, 2009.

Our Energy Services segment relies upon the investment grade rating of our senior unsecured long-term debt to satisfy credit requirements with most of our counterparties. If our credit ratings were to decline below investment grade, our ability to participate in energy marketing and trading activities could be significantly limited. Without an investment grade rating, we may be required to fund margin requirements with our counterparties with cash, letters of credit or other negotiable instruments. At December 31, 2005, the amount we could have been required to fund for the few counterparties with which we have a Credit Support Annex within our International Swaps and Derivatives Association Agreements is approximately $89.3 million. A decline in our credit rating below investment grade may also significantly impact other business segments.

We have reviewed our commercial paper agreement, trust indentures, building leases, equipment leases, marketing, trading and risk contracts, and other various contracts which may be subject to rating triggers, and we do not have significant exposure. Rating triggers are defined as provisions that would create an automatic default or acceleration of indebtedness based on a change in our credit rating. Our five-year credit and short-term bridge financing agreements contain a provision that would cause the cost to borrow funds to increase based on the amount borrowed under these agreements if our credit rating is negatively adjusted. The agreements also contain a default provision based on a material adverse change. An adverse rating change is not defined as a default or material adverse change.

Commodity Prices - We are subject to commodity price volatility. Significant fluctuations in commodity price in either physical or financial energy contracts may impact our overall liquidity due to the impact the commodity price change has on items such as the cost of NGLs and gas held in storage, increased margin requirements, collectibility of certain energy-related receivables and working capital. We believe that our current commercial paper program and debt capacity are adequate to meet our liquidity requirements associated with commodity price volatility.

Pension and Postretirement Benefit Plans - We calculate benefit obligations based upon generally accepted actuarial methodologies using the projected benefit obligation (PBO) for pension plans and the accumulated postretirement benefit obligation for other postretirement plans. Pension costs and other postretirement obligations as of December 31 are determined using a September 30 measurement date. The benefit obligations are the actuarial present value of all benefits attributed to employee service rendered. The PBO is measured using the pension benefit formula and assumptions as to future compensation levels. A plan's funded status is calculated as the difference between the benefit obligation and the fair value of plan assets. Our funding policy for the pension plans is to make annual contributions in accordance with regulations under the Internal Revenue Code and in accordance with generally accepted actuarial principles. Contributions made to the pension plan and postretirement benefit plan in 2005 were $1.5 million and $3.1 million, respectively. For 2006, we anticipate our total contributions to our defined benefit pension plan and postretirement benefit plan to be $1.7 million and $2.7 million, respectively, and our pay-as-you-go other postretirement benefit plan costs to be $14.0 million. We believe we have adequate resources to fund our obligations under our plans.

CASH FLOW ANALYSIS

Our Consolidated Statements of Cash Flows combines cash flows from discontinued operations with cash flows from continuing operations within each category. Discontinued operations accounted for approximately $77.2 million, $16.9 million and $(68.0) million in operating cash flows for the years ended December 31, 2005, 2004 and 2003, respectively. Discontinued operations accounted for approximately $(44.4), $(52.9) and $(18.7) million in investing cash flows for the years ended December 31, 2005, 2004 and 2003, respectively, and did not account for any financing cash flows. The absence of cash flows from our discontinued operations is not expected to have a significant impact on our future cash flows.

Operating Cash Flows - Operating cash flows decreased by $385.4 million for the year ended December 31, 2005, compared with the same period in 2004. The decrease in operating cash flows was primarily the result of a net increase in working capital of $301.3 million in 2004, compared with a net increase in working capital of $597.5 million in 2005. These increases primarily related to increases in accounts receivable and natural gas inventory, partially offset by increases in accounts payable.

Working capital changes had the opposite impact on 2004, compared with 2003, contributing to an increase in operating cash flows of $203.7 million.

The impact of higher commodity prices on accounts receivable, accounts payable and natural gas inventory negatively impacted operating cash flows for all periods. There is typically a lag between when payment is made for natural gas purchased for our distribution customers and when the customers are billed. This is due to the cycle billing process where distribution customers are billed throughout the month. Under level prices, this lag would have no impact on cash flows from year to year, but with increased prices, this lag resulted in a negative impact on cash flows.

Our Energy Services segment's deposits, or margin requirements, increase or decrease from year to year based on the level of open positions on our contracts as well as commodity prices and price volatility. With the increase in commodity prices at December 31, 2005, we were required to meet additional margin requirements, which also negatively impacted operating cash flows.

Investing Cash Flows - Acquisitions in 2005 primarily represent the cash purchase of the Koch assets. The sale of our Production segment resulted in proceeds from the sale of discontinued component. The proceeds from sale of assets in 2005 primarily resulted from the sale of our natural gas gathering and processing assets located in Texas. Additionally, the sale of Cimarex Energy Company common stock, formerly Magnum Hunter Resources (MHR) common stock, is also included in proceeds from sale of assets. This common stock was acquired upon exercise of MHR stock purchase warrants in February 2005, resulting in our paying $22.7 million, which is included in changes in other investments, net.

Acquisitions in 2004 represent the cash purchase of Northern Plains. Increased capital expenditures in 2004 were primarily incurred by our discontinued Production segment. Proceeds from the sale of assets include the sales of certain natural gas transmission and gathering pipelines, compression assets, natural gas distribution systems and investments in 2004.

Acquisitions in 2003 primarily represent the cash purchase of our Texas distribution assets and the purchase of natural gas and crude oil properties and related flow lines. Proceeds from the sale of discontinued component represents the sale of natural gas and crude oil producing properties for a cash sales price of $294 million, including adjustments, of which $15 million was received in 2002.

Financing Cash Flows - During 2005, we borrowed $1.0 billion under the short-term bridge financing agreement to assist in financing the acquisition of natural gas liquids assets from Koch. We funded the remaining acquisition cost through our commercial paper program. We reduced our indebtedness under our short-term bridge financing agreement by $100.0 million as a result of a required prepayment due to the sale of our Production segment.

During 2005, we paid $233.0 million to repurchase 7.5 million shares of our stock pursuant to a plan approved by our Board of Directors in 2005. This plan allows us to repurchase up to a total of 15 million shares of our common stock on or before November 17, 2007.

In December 2005, we made an early redemption of our 7.75 percent $300.0 million long-term notes with a stated maturity of August 2006. In addition to the principal payment, we were required to pay a make-whole call premium of $5.7 million and accrued interest of $8.7 million for a total payment of $314.4 million. We funded this early redemption with the proceeds from the sale of our natural gas gathering and processing assets located in Texas.

In June 2005, we issued $800 million of long-term notes and used a portion of the proceeds to repay commercial paper. The commercial paper had been issued to finance the Northern Border Partners acquisition, to repay $335 million of long-term debt that matured on March 1, 2005, and to meet operating needs. This increase was partially offset by $643 million in payments on notes payable and commercial paper, which represents the cash received from the sale of our Production segment, and payments made in the normal course of operations.

During the first quarter of 2005, we terminated $400 million of our interest rate swap agreements and paid a net amount of $19.4 million, which included $20.2 million for the present value of future payments at the time of termination, less $0.8 million for interest rate savings through the termination of the swaps. The $20.2 million payment has been recorded as a reduction in long-term debt and will be recognized in the income statement over the term of the debt instruments originally hedged. In the second quarter of 2005, we terminated $500 million of our treasury rate-lock agreements, which resulted in our paying $2.4 million. This amount, net of tax, has been recorded to accumulated other comprehensive loss and will be recognized in the income statement over the term of the related debt issuances.

During the first quarter of 2004, we repaid $600 million in notes payable using cash generated from operating activities and proceeds from our February 2004 equity offering. During the second half of 2004, we incurred $644 million of notes payable, which includes the acquisition of Northern Plains and funds used in the ordinary course of business.

We terminated $670 million of our interest rate swap agreements in the first quarter of 2004 to lock-in savings and generate a positive cash flow of $91.8 million, which included $8.9 million of interest savings previously recognized. These interest rate swaps were previously initiated as a strategy to hedge the fair value of fixed rate long-term debt. The proceeds received upon termination of the interest rate swaps, net of amounts previously recognized, will be recognized in the income statement over the term of the debt instruments originally hedged.

During the first quarter of 2004, we sold 6.9 million shares of our common stock to an underwriter at $21.93 per share, resulting in proceeds to us, before expenses, of $151.3 million.

During the first quarter of 2003, we issued a total of 16.1 million equity units at the public offering price of $25 per unit, resulting in aggregate net proceeds to us, after underwriting discounts and commissions, of $24.25 per share, or $390.4 million. Each equity unit consists of a stock purchase contract for the purchase of shares of our common stock and, initially, a senior note due February 16, 2008, issued pursuant to an Indenture with SunTrust Bank, as trustee. The equity units carry a total annual coupon rate of 8.5 percent (4.0 percent annual face amount of the senior notes plus 4.5 percent annual contract adjustment payments). The interest expense associated with the 4.0 percent senior notes will be recognized in the income statement on an accrual basis over the term of the senior notes. The present value of the contract adjustment payments was accrued as a liability with a charge to equity at the time of the transactions. Accordingly, there will be no impact on earnings in future periods as this liability is paid, except for the interest recognized as a result of discounting the liability to its present value at the time of the transaction. This interest expense will be approximately $3.5 million over three years. The present value of the contract adjustment payments is accounted for as equity and reduces paid in capital. The number of shares that we issued for each stock purchase contract issued as part of the equity units was determined based on our average closing price over the 20-trading day period ending on the third trading day prior to February 16, 2006.

Also, during the first quarter of 2003, we issued a total of 13.8 million shares of common stock at the public offering price of $17.19 per share, resulting in aggregate net proceeds to us, after underwriting discounts and commissions, of $16.524 per share, or $228 million.

In January 2003, we issued common stock and equity units, which were partially offset by the payment of notes payable and the repurchase of our Series A Convertible Preferred Stock from Westar in February 2003. In August 2003, we repurchased $50 million or approximately 2.6 million shares of our common stock from Westar.

CONTRACTUAL OBLIGATIONS AND COMMERICAL COMMITMENTS

We lease various buildings, facilities and equipment, which are accounted for as operating leases. We lease vehicles which are accounted for as operating leases for financial purposes and capital leases for tax purposes.

The following table sets forth our contractual obligations to make future payments under our current debt agreements, operating lease agreements and fixed price contracts. For further discussion of the debt and operating lease agreements, see Notes I and K, respectively, of Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

	Payments Due by Period						
Contractual Obligations	**Total**	**2006**	**2007**	**2008**	**2009**	**2010**	**Thereafter**
				(Thousands of dollars)			
Long-term debt	$ 1,993,202	$ 6,546	$ 6,563	$ 408,882	$ 107,596	$ 6,285	$ 1,457,330
Notes payable	1,541,500	1,541,500	-	-	-	-	-
Operating leases	247,218	59,982	43,853	41,482	38,464	26,813	36,624
Storage contracts	74,231	32,068	20,975	12,054	6,929	1,521	684
Firm transportation contracts	455,864	100,095	75,621	47,777	43,175	38,490	150,706
Purchase commitments,							
rights-of-way and other	14,230	3,471	2,114	1,975	1,787	1,746	3,137
Pension plan (a)	11,300	1,700	2,900	2,100	2,200	2,400	-
Other postretirement benefit plan (a)	86,529	16,711	17,052	17,289	17,534	17,943	-
Total contractual obligations	$ 4,424,074	$ 1,762,073	$ 169,078	$ 531,559	$ 217,685	$ 95,198	$ 1,648,481

(a) - No payment amounts are provided for our pension and other postretirement benefit plans in the "Thereafter" column since there is no termination date for these plans.

Long-term debt as reported in the consolidated balance sheets includes unamortized debt discount and the mark-to-market effect of interest rate swaps. Purchase commitments exclude commodity purchase contracts. Our Distribution segment is a party to fixed price transportation contracts. However, the costs associated with these contracts are recovered through rates as allowed by the applicable regulatory agency and are excluded from the table above.

OTHER

Environmental - We are subject to multiple environmental laws and regulations affecting many aspects of present and future operations, including air emissions, water quality, wastewater discharges, solid wastes and hazardous material and substance management. These laws and regulations generally require us to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals. Failure to comply with these laws, regulations, permits and licenses may expose us to fines, penalties and/or interruptions in our operations that could be material to the results of operations. If an accidental leak or spill of hazardous materials occurs from our lines or facilities, in the process of transporting natural gas or NGLs, or at any facility that we own, operate or otherwise use, we could be held jointly and severally liable for all resulting liabilities, including investigation and clean up costs, which could materially affect our results of operations and cash flow. In addition, emission controls required under the Federal Clean Air Act and other similar federal and state laws could require unexpected capital expenditures at our facilities. We cannot assure that existing environmental regulations will not be revised or that new regulations will not be adopted or become applicable to us. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have a material adverse effect on our business, financial condition and results of operations.

We own or retain legal responsibility for the environmental conditions at 12 former manufactured gas sites in Kansas. These sites contain potentially harmful materials that are subject to control or remediation under various environmental laws and regulations. A consent agreement with the KDHE presently governs all work at these sites. The terms of the consent agreement allow us to investigate these sites and set remediation activities based upon the results of the investigations and risk analysis. We have commenced active remediation on eight sites, with regulatory closure achieved at two of these locations, and have begun assessments at the four remaining sites. The site situations are not similar, and we have no previous experience with similar remediation efforts. We have completed some analysis of the four remaining sites, but are unable to accurately estimate individual or aggregate costs that may be required to satisfy our remedial obligations.

Our preliminary review of similar cleanup efforts at former manufactured gas sites reveals that costs can range from $100,000 to $10 million per site. These estimates do not consider potential insurance recoveries, recoveries through rates or from unaffiliated parties, to which we may be entitled. At this time, we have not recorded any amounts for potential insurance recoveries or recoveries from unaffiliated parties, and we are not recovering any environmental amounts in rates. Total costs to remediate the two sites, which have achieved regulatory closure, was approximately $700,000. Total remedial costs for each of the remaining sites are expected to exceed $500,000 per site, but there is no assurance that costs to investigate and remediate the remaining sites will not be significantly higher. As more information related to the site investigations and remediation activities becomes available, and to the extent such amounts are expected to exceed our current estimates, additional expenses could be recorded. Such amounts could be material to our results of operations and cash flows depending on the remediation done and number of years over which the remediation is completed.

Our expenditures for environmental evaluation and remediation to date have not been significant in relation to the results of operations and there were no material effects upon earnings during 2005 related to compliance with environmental regulations.

FORWARD-LOOKING STATEMENTS AND RISK FACTORS

Some of the statements contained and incorporated in this Annual Report on Form 10-K are forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. The forward-looking statements relate to: anticipated financial performance; management's plans and objectives for future operations; business prospects; outcome of regulatory and legal proceedings; market conditions and other matters. The Private Securities Litigation Reform Act of 1995 provides a safe harbor for forward-looking statements in certain circumstances. The following discussion is intended to identify important factors that could cause future outcomes to differ materially from those set forth in the forward-looking statements.

Forward-looking statements include the items identified in the preceding paragraph, the information concerning possible or assumed future results of our operations and other statements contained or incorporated in this Annual Report on Form 10-K identified by words such as "anticipate," "estimate," "expect," "forecast," "intend," "believe," "projection" or "goal."

You should not place undue reliance on forward-looking statements. Known and unknown risks, uncertainties and other factors may cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by forward-looking statements. Those factors may affect our operations, markets, products, services and prices. In addition to any assumptions and other factors referred to specifically in connection with the forward-looking statements, factors that could cause our actual results to differ materially from those contemplated in any forward-looking statement include, among others, the following:

- risks associated with any reduction in our credit ratings;
- the effects of weather and other natural phenomena on energy sales and prices, production and processing volumes, availability of supplies and other aspects of our business;
- competition from other energy suppliers as well as alternative forms of energy;
- the capital intensive nature of our business;
- the profitability of assets or businesses acquired by us;
- risks of marketing, trading and hedging activities as a result of changes in energy prices or the financial condition of our counterparties;
- economic climate and growth in the geographic areas in which we do business;
- the uncertainty of estimates, including accruals and costs of environmental remediation;
- the timing and extent of changes in commodity prices for natural gas, NGLs, power and crude oil, including basis differentials for natural gas and NGLs;
- the effects of changes in governmental policies and regulatory actions, including changes with respect to income taxes, environmental compliance, pipeline integrity, authorized rates or recovery of gas costs and ERISA;
- the impact of recently issued and future accounting pronouncements and other changes in accounting policies;
- the possibility of future terrorist attacks or the possibility or occurrence of an outbreak of, or changes in, hostilities or changes in the political conditions in the Middle East and elsewhere;
- the risk of increased costs for insurance premiums, security or other items as a consequence of terrorist attacks;
- risks associated with casualty losses, including casualty losses at plant sites that could interrupt portions of our business;
- the impact of changes in interest rates, equity markets, inflation rates, economic recession and other external factors over which we have no control, including the effect on pension expense and funding resulting from changes in stock and bond market returns;
- risks associated with pending or possible acquisitions and dispositions, including our ability to finance or integrate any such acquisitions and any regulatory delay or conditions imposed by regulatory bodies in connection with any such acquisitions and dispositions;

- the results of administrative proceedings and litigation involving the OCC, KCC, Texas regulatory authorities or any other local, state or federal regulatory body, including the FERC;
- our ability to access capital at competitive rates or on terms acceptable to us;
- the risk of a significant slowdown in growth or decline in the U.S. economy or the risk of delay in growth or recovery in the U.S. economy;
- risks associated with adequate supply to our gathering, processing, fractionation and pipeline facilities, including production declines which outpace new drilling;
- risks of fines in the event of accidents and/or accidental releases of natural gas or NGLs;
- risks inherent in the implementation of new software, such as our customer service system, and the impact on the timeliness of information for financial reporting;
- the risk that material weaknesses or significant deficiencies in our internal controls over financial reporting could emerge or that minor problems could become significant;
- the impact of the outcome of pending and future litigation;
- the possible loss of franchises or other adverse effects caused by the actions of municipalities;
- changes in law or increase in competition resulting from new federal energy legislation, including the repeal of the Public Utility Holding Company Act of 1935;
- risks of holding a majority of the general partnership interest in Northern Border Partners, LP, a publicly-traded limited partnership; and
- the other factors listed in the reports we have filed and may file with the Securities and Exchange Commission, which are incorporated by reference.

Other factors and assumptions not identified above were also involved in the making of the forward-looking statements. The failure of those assumptions to be realized, as well as other factors, may also cause actual results to differ materially from those projected. We have no obligation and make no undertaking to update publicly or revise any forward-looking information.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

COMMODITY PRICE RISK

Non-Regulated Businesses, Including Energy Services - We are exposed to market risk and the impact of market price fluctuations of natural gas, NGLs, crude oil and power prices. Market risk refers to the risk of loss in cash flows and future earnings arising from adverse changes in commodity energy prices. Our primary exposure arises from fixed price purchase or sale agreements that extend for periods of up to three years, natural gas in storage utilized by our Energy Services segment, NGLs in storage utilized by our Natural Gas Liquids segment, the difference in price between natural gas and NGL prices with respect to our keep whole processing agreements, and purchases of natural gas and crude oil. To a lesser extent, we are exposed to the risk of changing prices or the cost of intervening transportation resulting from purchasing natural gas and NGLs at one location and selling it at another (referred to as basis risk). To minimize the risk from market price fluctuations of natural gas, NGLs and crude oil, we use commodity derivative instruments such as futures contracts, swaps and options to manage market risk of existing or anticipated purchase and sale agreements, existing physical natural gas in storage, and basis risk. We adhere to policies and procedures that limit our exposure to market risk from open positions and that monitor our market risk exposure.

The following table sets forth the fair value component of the energy marketing and risk management assets and liabilities, excluding derivative instruments that have been declared as either fair value or cash flow hedges.

Fair Value Component of Energy Marketing and Risk Management Assets and Liabilities

(Thousands of dollars)

Net fair value of contracts outstanding at December 31, 2004	$ 17,951
Contracts realized or otherwise settled during the period	18,326
Fair value of new contracts when entered into during the period	3,596
Other changes in fair value	(9,537)
Net fair value of contracts outstanding at December 31, 2005	$ 30,336

The net fair value of contracts outstanding includes the effect of settled energy contracts and current period changes resulting primarily from newly originated transactions and the impact of market movements on the fair value of energy marketing and risk management assets and liabilities. Fair value estimates consider the market in which the transactions are executed. The market in which exchange traded and over-the-counter transactions are executed is a factor in determining fair value. We utilize third-party references for pricing points from NYMEX and third-party over-the-counter brokers to establish the commodity pricing and volatility curves. We believe the reported transactions from these sources are the most reflective of current market prices. Fair values are subject to change based on valuation factors. The estimate of fair value includes an adjustment for the liquidation of the position in an orderly manner over a reasonable period of time under current market conditions. The fair value estimate also considers the risk of nonperformance based on credit considerations of the counterparty.

The following table sets forth the maturity schedule of our energy trading contracts based on the heating season from April through March. This maturity schedule is consistent with our business strategy.

	Fair Value of Contracts at December 31, 2005			
Fair Value (a)	**Matures through March 2006**	**Matures through March 2009**	**Matures through March 2011**	**Total Fair Value**
	(Thousands of dollars)			
Prices actively quoted (b)	$ 80,531	$ 4,522	$ -	$ 85,053
Prices provided by other external sources (c)	(43,316)	11,289	(1,731)	(33,758)
Prices derived from quotes, other external sources and other assumptions (d)	(6,864)	(17,046)	2,951	(20,959)
Total	$ 30,351	$ (1,235)	$ 1,220	$ 30,336

(a) Fair value is the mark-to-market component of forwards, futures, swaps and options, net of applicable reserves. These fair values are reflected as a component of assets and liabilities from energy marketing and risk management activities in our Consolidated Balance Sheets.

(b) Values are derived from the energy market price quotes from national commodity trading exchanges that primarily trade future and option commodity contracts.

(c) Values are obtained through energy commodity brokers or electronic trading platforms, whose primary service is to match willing buyers and sellers of energy commodities. Energy price information by location is readily available because of the large energy broker network.

(d) Values derived in this category utilize market price information from the other two categories, as well as other assumptions for liquidity and credit.

The following table sets forth our Energy Services segment's financial and commodity risk from fixed-price transactions at December 31, 2005.

	Investment Grade Credit Quality (a)	**Below Investment Grade Credit Quality**
	(Thousands of dollars)	
Gas and electric utilities	$ (27,873)	$ (16,859)
Financial institutions	(45,844)	-
Oil and gas producers	14,719	12,209
Industrial and commercial	5,262	7,320
Other	(28,571)	565
Net value of fixed-price transactions	$ (82,307)	$ 3,235

(a) Investment grade is primarily determined using publicly available credit ratings along with consideration of cash prepayments, cash managing, standby letters of credit and parent company guarantees. Included in Investment Grade are counterparties with a minimum S&P rating of BBB- or Moody's rating of Baa3.

For further discussion of trading activities, see the Critical Accounting Policies and Estimates section of Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation in this Annual Report on Form 10-K. Also, see Note D of the Notes to Consolidated Financial Statements in this Form 10-K.

Regulated Businesses - Kansas Gas Service uses derivative instruments to hedge the cost of anticipated natural gas purchases during the winter heating months to protect Kansas Gas Service customers from upward volatility in the market price of natural gas. At December 31, 2005, Kansas Gas Service had derivative instruments in place to hedge the cost of natural gas purchases for 2.4 Bcf, which represents part of their gas purchase requirements for the 2005/2006 winter heating months. Gains or losses associated with the Kansas Gas Service hedges are included in and recoverable through the monthly PGA.

Value-at-Risk (VAR) Disclosure of Market Risk - We measure market risk in the energy marketing and risk management, trading and non-trading portfolios of our non-regulated businesses using a VAR methodology, which estimates the expected maximum loss of the portfolio over a specified time horizon within a given confidence interval. Our VAR calculations are based on the Monte Carlo approach. The quantification of market risk using VAR provides a consistent measure of risk across diverse energy markets and products with different risk factors in order to set overall risk tolerance, to determine risk targets and set position limits. The use of this methodology requires a number of key assumptions, including the selection of a confidence level and the holding period to liquidation. Inputs to the calculation include prices, volatilities, positions, instrument valuations and the variance-covariance matrix. Historical data is used to estimate our VAR with more weight given to recent data, which is considered a more relevant predictor of immediate future commodity market movements. We rely on VAR to determine the potential reduction in the portfolio values arising from changes in market conditions over a defined period. While management believes that the referenced assumptions and approximations are reasonable, no uniform industry methodology exists for estimating VAR. Different assumptions and approximations could produce materially different VAR estimates.

Our VAR exposure represents an estimate of potential losses that would be recognized for our non-regulated businesses' energy marketing and risk management, non-trading and trading portfolios of derivative financial instruments, physical contracts and natural gas in storage due to adverse market movements. A one-day time horizon and a 95 percent confidence level were used in our VAR data. Actual future gains and losses will differ from those estimated by the VAR calculation based on actual fluctuations in commodity prices, operating exposures and timing thereof, and the changes in our derivative financial instruments, physical contracts and natural gas in storage. VAR information should be evaluated in light of these assumptions and the methodology's other limitations.

The potential impact on our future earnings, as measured by the VAR, was $30.1 million and $9.6 million at December 31, 2005 and 2004, respectively. The following table details the average, high and low VAR calculations.

	Years Ended December 31,	
Value-at-Risk	**2005**	**2004**
	(Millions of dollars)	
Average	**$ 16.4**	$ 3.8
High	**$ 44.0**	$ 17.7
Low	**$ 6.2**	$ 0.6

The variations in the VAR data are reflective of market volatility and changes in the portfolios during the year. The 2005 increase in VAR, compared with 2004, is primarily due to the increase in natural gas prices in the third and fourth quarters of 2005, which mainly resulted from supply disruption caused by Hurricane Katrina and Hurricane Rita.

Risk Policy and Oversight - We control the scope of risk management, marketing and trading operations through a comprehensive set of policies and procedures involving senior levels of management. The audit committee of our Board of Directors has oversight responsibilities for our risk management limits and policies. Our risk oversight committee, comprised of corporate officers, oversees all activities related to commodity price, credit and interest rate risk management, and marketing and trading activities. The committee also proposes risk metrics including VAR and dollar loss limits. We have a corporate risk control organization led by our Senior Vice President of Financial Services and Treasurer and our Vice President of Audit and Risk Control, who are assigned responsibility for establishing and enforcing the policies, procedures and limits. Key risk control activities include credit review and approval, credit and performance risk measurement and monitoring, validation of transactions, portfolio valuation, VAR and other risk metrics.

To the extent open commodity positions exist, fluctuating commodity prices can impact our financial results and financial position either favorably or unfavorably. As a result, we cannot predict with precision the impact risk management decisions may have on the business, operating results or financial position.

INTEREST RATE AND CURRENCY RISK

Interest Rate Risk - We are subject to the risk of interest rate fluctuation in the normal course of business. We manage interest rate risk through the use of fixed rate debt, floating rate debt and, at times, interest rate swaps. Fixed rate swaps are used to reduce our risk of increased interest costs during periods of rising interest rates. Floating rate swaps are used to convert the fixed rates of long-term borrowings into short-term variable rates. At December 31, 2005, the interest rate on 82.8 percent of our long-term debt was fixed after considering the impact of interest rate swaps.

During the first quarter of 2005, we terminated $400 million of our interest rate swap agreements and paid a net amount of $19.4 million, which included $20.2 million for the present value of future payments at the time of termination, less $0.8 million for interest rate savings through the termination of the swaps. During the first quarter of 2004, we terminated $670 million of our interest rate swap agreements and received $81.9 million. The net savings from the termination of these swaps is being recognized in interest expense over the terms of the debt instruments originally hedged. Net interest expense savings for 2005 for all terminated swaps was $7.7 million, and the remaining net savings for all terminated swaps will be recognized over the following periods:

2006	$6.8 million
2007	$6.6 million
2008	$6.6 million
2009	$5.6 million
2010	$5.5 million
Thereafter	$15.3 million

Currently, $340 million of fixed rate debt is swapped to floating. The floating rate debt is based on both the three- and six-month London InterBank Offered Rate (LIBOR). At December 31, 2005, we recorded a net liability of $7.3 million to recognize the interest rate swaps at fair value. Long-term debt was decreased by $7.3 million to recognize the change in the fair value of the related hedged liability. See Note I.

Total swap savings for 2005 were $10.7 million, compared with the savings of $27.6 million in 2004.

Prior to the issuance of the $800 million of notes in the second quarter of 2005, we entered into $500 million in treasury rate-lock agreements to hedge the changes in cash flows of our anticipated interest payments from changes in treasury rates prior to the issuance of the notes. Upon issuance of the notes in June 2005, the treasury rate-lock agreements terminated, which resulted in our paying $2.4 million. This amount, net of tax, has been recorded to accumulated other comprehensive loss and will be recognized in the income statement over the term of the related debt issuances.

At December 31, 2005, a 100 basis point move in the annual interest rate on all of our outstanding long-term debt would change our annual interest expense by $3.4 million before taxes. This 100 basis point change assumes a parallel shift in the yield curve. If interest rates changed significantly, we would take actions to manage our exposure to the change. Since a specific action and the possible effects are uncertain, no change has been assumed.

Currency Rate Risk - With our Energy Services segment's expansion into Canada, we are subject to currency exposure related to our firm transportation and storage contracts. Our objective with respect to currency risk is to reduce the exposure due to exchange-rate fluctuations. We use physical forward transactions, which result in an actual two-way flow of currency on the settlement date since we exchange U.S. dollars for Canadian dollars with another party. We have not designated these transactions for hedge accounting treatment; therefore, the gains and losses associated with the change in fair value are recorded in net margin. At December 31, 2005 and 2004, our exposure to risk from currency translation was not material.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders
ONEOK, Inc.:

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting (Item 9A(b)), that ONEOK, Inc. maintained effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). ONEOK, Inc.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

A material weakness is a control deficiency, or combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected. The following material weakness has been identified and included in management's assessment:

> The Company's third party software system associated with accounting for derivative hedging instruments was inadequately designed to appropriately account for certain hedges of forecasted transactions and thus did not facilitate the recognition of hedging ineffectiveness in accordance with generally accepted accounting principles. The software system incorrectly reversed previously recognized hedging ineffectiveness when additional derivative instruments (basis swaps) were incorporated into the Company's hedging strategy related to the forecasted transactions. As a result, misstatements were identified in the Company's cost of sales and fuel account and accumulated other comprehensive income (loss).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of ONEOK, Inc. and subsidiaries as of December 31, 2005 and 2004, and the related consolidated statements of income, shareholders' equity and comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2005. The aforementioned material weakness was considered in determining the nature, timing, and extent of audit tests applied in our audit of the 2005 consolidated financial statements, and this report does not affect our report dated March 10, 2006 which expressed an unqualified opinion on those consolidated financial statements.

In our opinion, management's assessment that ONEOK, Inc. did not maintain effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Also, in our opinion, because of the effect of the material weakness described above on the achievement of the objectives of the control criteria, ONEOK, Inc. has not maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

The Company acquired Koch Industries, Inc.'s natural gas liquids business in July 2005 (herein after referred to as "the Natural Gas Liquids segment"), and management excluded from its assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2005, internal control over financial reporting associated with the Natural Gas Liquids segment, which represents approximately 19 percent of total consolidated revenue in 2005 and approximately 16 percent of consolidated total assets included in the consolidated financial statements as of and for the year ended December 31, 2005. Our audit of internal control over financial reporting of the Company also excluded an evaluation of the internal control over financial reporting of the Natural Gas Liquids segment.

KPMG LLP

Tulsa, Oklahoma
March 10, 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
ONEOK, Inc.:

We have audited the accompanying consolidated balance sheets of ONEOK, Inc. and subsidiaries as of December 31, 2005 and 2004, and the related consolidated statements of income, shareholders' equity and comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2005. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of ONEOK, Inc. and subsidiaries as of December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2005, in conformity with U.S. generally accepted accounting principles.

As discussed in Note A to the consolidated financial statements, the Company adopted the provisions of Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations, the recognition and measurement principles of Statement of Financial Accounting Standards No. 123, Accounting for Stock-Based Compensation, and the rescission of the provisions of Emerging Issues Task Force 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities, effective January 1, 2003.

We also have audited in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of ONEOK, Inc.'s internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 10, 2006, expressed an unqualified opinion on management's assessment of, and an adverse opinion on the effective operation of, internal control over financial reporting.

KPMG LLP

Tulsa, Oklahoma
March 10, 2006

ONEOK, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31,		
	2005	**2004**	**2003**
Revenues	*(Thousands of dollars, except per share amounts)*		
Operating revenues, excluding energy trading revenues	**$12,663,550**	$ 5,671,714	$ 2,640,684
Energy trading revenues, net	**12,680**	113,814	229,782
Total Revenues	**12,676,230**	5,785,528	2,870,466
Cost of sales and fuel	**11,338,076**	4,648,311	1,785,648
Net Margin	**1,338,154**	1,137,217	1,084,818
Operating Expenses			
Operations and maintenance	**552,531**	475,106	449,006
Depreciation, depletion and amortization	**183,394**	158,053	144,695
General taxes	**67,464**	60,406	63,262
Total Operating Expenses	**803,389**	693,565	656,963
Gain on Sale of Assets	**264,207**	-	-
Operating Income	**798,972**	443,652	427,855
Other income	**14,188**	17,599	8,128
Other expense	**19,883**	12,056	5,198
Interest expense	**147,608**	87,301	98,232
Income before Income Taxes	**645,669**	361,894	332,553
Income taxes	**242,521**	137,221	126,104
Income from Continuing Operations	**403,148**	224,673	206,449
Discontinued operations, net of taxes (Note C):			
Income (loss) from operations of discontinued components, net of	**(6,180)**	17,505	10,185
Gain on sale of discontinued component, net of tax	**149,577**	-	39,739
Cumulative effect of changes in accounting principles,			
net of tax (Note A and D)	**-**	-	(143,885)
Net Income	**546,545**	242,178	112,488
Preferred stock dividends	**-**	-	24,211
Income Available for Common Stock	**$ 546,545**	$ 242,178	$ 88,277
Earnings Per Share of Common Stock (Note Q)			
Basic:			
Earnings per share from continuing operations	**$ 4.01**	$ 2.21	$ 2.28
Earnings (loss) per share from operations			
of discontinued components, net	**(0.06)**	0.17	0.12
Earnings per share from gain on sale			
of discontinued component, net	**1.49**	-	0.36
Earnings per share from cumulative effect of			
changes in accounting principles	**-**	-	(1.28)
Net Earnings Per Share, Basic	**$ 5.44**	$ 2.38	$ 1.48
Diluted:			
Earnings per share from continuing operations	**$ 3.73**	$ 2.13	$ 2.05
Earnings (loss) per share from operations			
of discontinued components, net	**(0.06)**	0.17	0.10
Earnings per share from gain on sale			
of discontinued component, net	**1.39**	-	0.35
Earnings per share from cumulative effect of			
changes in accounting principles	**-**	-	(1.28)
Net Earnings Per Share, Diluted	**$ 5.06**	$ 2.30	$ 1.22
Average Shares of Common Stock *(Thousands)*			
Basic	**100,536**	101,965	80,569
Diluted	**108,006**	105,461	96,999
Dividends Declared Per Share of Common Stock	**$ 1.09**	$ 0.88	$ 0.69

See accompanying Notes to Consolidated Financial Statements.

ONEOK, Inc. and Subsidiaries
CONSOLIDATED BALANCE SHEETS

	December 31, 2005	December 31, 2004
Assets	*(Thousands of dollars)*	
Current Assets		
Cash and cash equivalents	**$ 7,915**	$ 9,458
Trade accounts and notes receivable, net	**2,202,895**	1,412,861
Gas and natural gas liquids in storage	**911,393**	593,028
Commodity exchanges	**133,159**	1,758
Energy marketing and risk management assets (Note D)	**765,157**	386,781
Other current assets	**385,274**	90,566
Total Current Assets	**4,405,793**	2,494,452
Property, Plant and Equipment		
Property, plant and equipment	**5,575,365**	4,832,876
Accumulated depreciation, depletion and amortization	**1,581,138**	1,519,719
Net Property, Plant and Equipment	**3,994,227**	3,313,157
Deferred Charges and Other Assets		
Goodwill and intangibles (Note E)	**683,211**	225,188
Energy marketing and risk management assets (Note D)	**150,026**	71,310
Investments and other	**716,298**	589,805
Total Deferred Charges and Other Assets	**1,549,535**	886,303
Assets of Discontinued Component	**63,911**	505,240
Total Assets	**$10,013,466**	$ 7,199,152

See accompanying Notes to Consolidated Financial Statements.

ONEOK, Inc. and Subsidiaries
CONSOLIDATED BALANCE SHEETS

	December 31, 2005	December 31, 2004
Liabilities and Shareholders' Equity	*(Thousands of dollars)*	
Current Liabilities		
Current maturities of long-term debt	**$ 6,546**	$ 341,532
Notes payable	**1,541,500**	644,000
Accounts payable	**1,756,307**	1,161,984
Commodity exchanges	**238,176**	-
Energy marketing and risk management liabilities (Note D)	**814,803**	403,626
Other	**438,009**	337,653
Total Current Liabilities	**4,795,341**	2,888,795
Long-term Debt, excluding current maturities	**2,024,070**	1,543,202
Deferred Credits and Other Liabilities		
Deferred income taxes	**603,835**	601,281
Energy marketing and risk management liabilities (Note D)	**442,842**	102,865
Other deferred credits	**350,157**	371,130
Total Deferred Credits and Other Liabilities	**1,396,834**	1,075,276
Liabilities of Discontinued Component	**2,464**	86,175
Total Liabilities	**8,218,709**	5,593,448
Commitments and Contingencies (Note K)		
Shareholders' Equity		
Common stock, $0.01 par value: authorized 300,000,000 shares; issued 107,973,436 shares and outstanding 97,654,697 shares at December 31, 2005; issued 107,143,722 shares and outstanding 104,106,285 shares at December 31, 2004	**1,080**	1,071
Paid in capital	**1,044,283**	1,017,603
Unearned compensation	**(105)**	(1,413)
Accumulated other comprehensive loss (Note F)	**(56,991)**	(9,591)
Retained earnings	**1,085,845**	649,240
Treasury stock, at cost: 10,318,739 shares at December 31, 2005 and 3,037,437 shares at December 31, 2004	**(279,355)**	(51,206)
Total Shareholders' Equity	**1,794,757**	1,605,704
Total Liabilities and Shareholders' Equity	**$10,013,466**	$ 7,199,152

See accompanying Notes to Consolidated Financial Statements.

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ONEOK, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2005	**2004**	**2003 Revised**
Operating Activities	*(Thousands of Dollars)*		
Net income	**$ 546,545**	$ 242,178	$ 112,488
Depreciation, depletion and amortization	**183,394**	158,053	144,695
Impairment expense on discontinued operations	**52,226**	-	-
Cumulative effect of changes in accounting principles, net	**-**	-	143,885
Gain on sale of discontinued component, net	**(149,577)**	-	(39,739)
Gain on sale of assets	**(269,040)**	(10,586)	(286)
Income from equity investments, net	**9,705**	(1,506)	(307)
Deferred income taxes	**16,372**	91,238	115,368
Stock based compensation expense	**11,842**	14,330	6,289
Allowance for doubtful accounts	**16,329**	13,309	14,073
Changes in assets and liabilities (net of acquisition and disposition effects):			
Accounts and notes receivable	**(733,367)**	(476,017)	(156,792)
Inventories	**(320,632)**	(96,510)	(428,227)
Unrecovered purchased gas costs	**(8,943)**	12,944	54,954
Commodity exchanges	**106,775**	-	-
Deposits	**(118,214)**	10,030	(42,424)
Regulatory assets	**(6,357)**	(15,395)	(4,586)
Accounts payable and accrued liabilities	**518,406**	322,387	99,516
Energy marketing and risk management assets and liabilities	**223,965**	(22,033)	27,651
Other assets and liabilities	**(259,088)**	(36,718)	(44,592)
Cash Provided by (Used in) Operating Activities	**(179,659)**	205,704	1,966
Investing Activities			
Changes in other investments, net	**(23,864)**	1,891	(2,366)
Acquisitions	**(1,327,907)**	(176,709)	(690,302)
Capital expenditures	**(250,493)**	(264,110)	(215,148)
Proceeds from sale of discontinued component	**519,279**	-	280,669
Proceeds from sale of assets	**556,434**	21,241	3,084
Other investing activities	**(6,862)**	(5,603)	3,635
Cash Used in Investing Activities	**(533,413)**	(423,290)	(620,428)
Financing Activities			
Borrowing of notes payable, net	**897,500**	44,000	334,500
Issuance of debt, net of issuance costs	**798,792**	-	402,400
Termination of interest rate swaps	**(22,565)**	82,915	-
Payment of debt	**(636,288)**	(1,364)	(16,148)
Purchase of Series A Convertible Preferred Stock	**-**	-	(300,000)
Purchase of common stock	**(228,149)**	-	(50,000)
Issuance of common stock	**16,372**	189,777	224,412
Issuance (purchase) of treasury stock, net	**-**	(823)	12,616
Dividends paid	**(110,157)**	(89,229)	(71,242)
Other financing activities	**(3,976)**	(10,404)	20,574
Cash Provided by Financing Activities	**711,529**	214,872	557,112
Change in Cash and Cash Equivalents	**(1,543)**	(2,714)	(61,350)
Cash and Cash Equivalents at Beginning of Period	**9,458**	12,172	73,522
Cash and Cash Equivalents at End of Period	**$ 7,915**	$ 9,458	$ 12,172

See accompanying Notes to Consolidated Financial Statements. See Note A for discussion of 2003 revision.

ONEOK, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME

	Common Stock Issued	Preferred Stock Issued	Series A Convertible Preferred Stock	Series D Convertible Preferred Stock	Common Stock	Paid-in Capital
	(Shares)			*(Thousands of dollars)*		
December 31, 2002	63,438,441	19,946,448	$ 199	$ -	$ 634	$ 903,918
Net income	-	-	-	-	-	-
Other comprehensive loss	-	-	-	-	-	-
Total comprehensive income						
Re-issuance of treasury stock		-	-	-	-	1,608
Common stock offering	13,800,000	-	-	-	138	227,893
Common stock issuance pursuant to various plans	-	-	-	-	-	6,029
Issuance costs of equity units	-	-	-	-	-	(9,728)
Contract adjustment payment	-	-	-	-	-	(50,805)
Repurchase of Series A Convertible Preferred Stock	18,077,511	(9,038,755)	(90)	-	181	(91)
Exchange of Series A Convertible Preferred Stock	-	(10,907,693)	(109)	-	-	(308,466)
Issuance of Series D Convertible Preferred Stock	-	21,815,386	-	218	-	361,747
Repurchase of common stock	-	-	-	-	-	-
Exchange of Series D Convertible Preferred Stock	-	(8,418,000)	-	(84)	-	(137,551)
Conversion of Series D Convertible Preferred Stock	2,551,835	(13,397,386)	-	(134)	26	(182,035)
Issuance of restricted stock	-	-	-	-	-	107
Forfeiture of restricted stock	-	-	-	-	-	-
Registration Costs	-	-	-	-	-	(268)
Stock-based employee compensation expense	326,887	-	-	-	3	3,512
Convertible preferred stock dividends	-	-	-	-	-	-
Common stock dividends - $0.69 per share	-	-	-	-	-	-
December 31, 2003	98,194,674	-	$ -	$ -	$ 982	$ 815,870

See accompanying Notes to Consolidated Financial Statements.

ONEOK, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME
(Continued)

	Unearned Compensation	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Treasury Stock	Total
			(Thousands of dollars)		
December 31, 2002	$(2,716)	$ (5,546)	$ 507,836	$ (38,713)	$ 1,365,612
Net income	-	-	112,488	-	112,488
Other comprehensive loss	-	(12,080)	-	-	(12,080)
Total comprehensive income					100,408
Re-issuance of treasury stock	-	-	-	15,458	17,066
Common stock offering	-	-	-	-	228,031
Common stock issuance pursuant to various plans	-	-	-	-	6,029
Issuance costs of equity units	-	-	-	-	(9,728)
Contract adjustment payment	-	-	-	-	(50,805)
Repurchase of Series A Convertible Preferred Stock	-	-	-	(300,000)	(300,000)
Exchange of Series A Convertible Preferred Stock	-	-	-	-	(308,575)
Issuance of Series D Convertible Preferred Stock	-	-	(53,390)	-	308,575
Repurchase of common stock	-	-	-	(50,000)	(50,000)
Exchange of Series D Convertible Preferred Stock	-	-	-	137,635	-
Conversion of Series D Convertible Preferred Stock	-	-	-	182,143	-
Issuance of restricted stock	(3,206)	-	-	3,099	-
Forfeiture of restricted stock	5	-	-	(5)	-
Registration Costs	-	-	-	-	(268)
Stock-based employee compensation expense	2,774	-	-	-	6,289
Convertible preferred stock dividends	-	-	(18,753)	-	(18,753)
Common stock dividends - $0.69 per share	(279)	-	(52,210)	-	(52,489)
December 31, 2003	$(3,422)	$ (17,626)	$ 495,971	$ (50,383)	$ 1,241,392

ONEOK, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME

	Common Stock Issued	Preferred Stock Issued	Series A Convertible Preferred Stock	Series D Convertible Preferred Stock	Common Stock	Paid-in Capital
	(Shares)			*(Thousands of dollars)*		
December 31, 2003	98,194,674	-	$ -	$ -	$ 982	$ 815,870
Net income	-	-	-	-	-	-
Other comprehensive income	-	-	-	-	-	-
Total comprehensive income						
Receipts and forfeitures of restricted stock	-	-	-	-	-	-
Common stock offering	6,900,000	-	-	-	69	151,248
Common stock issuance pursuant to various plans	2,049,048	-	-	-	20	38,736
Offering costs	-	-	-	-	-	(296)
Stock-based employee compensation expense	-	-	-	-	-	12,045
Common stock dividends - $0.88 per share	-	-	-	-	-	-
December 31, 2004	107,143,722	-	-	-	1,071	1,017,603
Net income	-	-	-	-	-	-
Other comprehensive loss	-	-	-	-	-	-
Total comprehensive income						
Repurchase of common stock	-	-	-	-	-	-
Common stock issuance pursuant to various plans	829,714	-	-	-	9	16,363
Stock-based employee compensation expense	-	-	-	-	-	10,317
Common stock dividends - $1.09 per share	-	-	-	-	-	-
December 31, 2005	**107,973,436**	**-**	**$ -**	**$ -**	**$1,080**	**$ 1,044,283**

See accompanying Notes to Consolidated Financial Statements.

ONEOK, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME
(Continued)

	Unearned Compensation	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Treasury Stock	Total
			(Thousands of dollars)		
December 31, 2003	$(3,422)	$ (17,626)	$ 495,971	$ (50,383)	$ 1,241,392
Net income	-	-	242,178	-	242,178
Other comprehensive income	-	8,035	-	-	8,035
Total comprehensive income					250,213
Receipts and forfeitures of restricted stock	44	-	-	(823)	(779)
Common stock offering	-	-	-	-	151,317
Common stock issuance pursuant to various plans	-	-	-	-	38,756
Offering costs	-	-	-	-	(296)
Stock-based employee compensation expense	2,285	-	-	-	14,330
Common stock dividends - $0.88 per share	(320)	-	(88,909)	-	(89,229)
December 31, 2004	(1,413)	(9,591)	649,240	(51,206)	$ 1,605,704
Net income	-	-	546,545	-	546,545
Other comprehensive loss	-	(47,400)	-	-	(47,400)
Total comprehensive income					499,145
Repurchase of common stock	-	-	-	(228,149)	(228,149)
Common stock issuance pursuant to various plans	-	-	-	-	16,372
Stock-based employee compensation expense	1,525	-	-	-	11,842
Common stock dividends - $1.09 per share	(217)	-	(109,940)	-	(110,157)
December 31, 2005	**$ (105)**	**$ (56,991)**	**$ 1,085,845**	**$ (279,355)**	**$ 1,794,757**

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A. SUMMARY OF ACCOUNTING POLICIES

Nature of Operations - We purchase, gather, process, transport, store and distribute natural gas. We extract, fractionate, store, transport, sell and market natural gas liquids (NGLs); and are engaged in natural gas, crude oil, NGLs and electricity marketing, retail natural gas marketing and trading activities. We are the largest natural gas distributor in Oklahoma and Kansas and the third largest natural gas distributor in Texas, providing service as a regulated public utility to wholesale and retail customers. Our largest distribution markets are Oklahoma City and Tulsa, Oklahoma; Kansas City, Wichita, and Topeka, Kansas; and Austin and El Paso, Texas. Our energy services operations provide services to customers in many states. We acquired Northern Plains Natural Gas Company and its wholly owned subsidiary Pan Border Gas Company (collectively, Northern Plains) in November 2004. As a result of this acquisition, we are the majority general partner of Northern Border Partners, one of the largest publicly-traded master limited partnerships. Northern Border Partners acquires, owns and manages pipelines and other midstream energy assets and is a leading transporter of natural gas imported from Canada into the United States.

Critical Accounting Policies

The following is a summary of our most critical accounting policies, which are defined as those policies most important to the portrayal of our financial condition and results of operations and requiring management's most difficult, subjective, or complex judgment, particularly because of the need to make estimates concerning the impact of inherently uncertain matters. We have discussed the development of and selection of our critical accounting policies and estimates with the audit committee of our Board of Directors.

Derivatives and Risk Management Activities - We engage in wholesale energy marketing, retail marketing, trading, and risk management activities. We account for derivative instruments utilized in connection with these activities and services under the fair value basis of accounting in accordance with the Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards No. 133, “Accounting for Derivative Instruments and Hedging Activities” (Statement 133), as amended. Many of our purchase and sale agreements that otherwise would be required to follow derivative accounting qualify as normal purchases and normal sales under Statement 133 and are therefore exempt from fair value accounting treatment.

Under Statement 133, entities are required to record derivative instruments at fair value. The fair value of derivative instruments is determined by commodity exchange prices, over-the-counter quotes, volatility, time value, counterparty credit and the potential impact on market prices of liquidating positions in an orderly manner over a reasonable period of time under current market conditions. The majority of our portfolio’s fair values are based on actual market prices. Market value changes result in a change in the fair value of our derivative instruments. The accounting for changes in the fair value of a derivative instrument depends on whether it has been designated and qualifies as part of a hedging relationship and, if so, the reason for holding it. If the derivative instrument does not qualify or is not designated as part of a hedging relationship, we account for changes in fair value of the derivative in earnings as they occur. Commodity price volatility may have a significant impact on the gain or loss in any given period.

To minimize the risk of fluctuations in natural gas, NGLs and crude oil prices, we periodically enter into futures transactions and swaps in order to hedge anticipated purchases of natural gas and crude oil, fuel requirements and NGL inventories. Interest rate swaps are also used to manage interest rate risk. Under certain conditions, we designate these derivative instruments as a hedge of exposure to changes in fair values or cash flows. For hedges of exposure to changes in fair value, the gain or loss on the derivative instrument is recognized in earnings in the period of change together with the offsetting loss or gain on the hedged item attributable to the risk being hedged. For hedges of exposure to changes in cash flow, the effective portion of the gain or loss on the derivative instrument is reported initially as a component of other comprehensive income and is subsequently reclassified into earnings when the forecasted transaction affects earnings. Any ineffectiveness of designated hedges is reported in earnings in the period the ineffectiveness occurs.

In October 2002, the Emerging Issues Task Force (EITF) of the FASB rescinded EITF Issue No. 98-10, “Accounting for Contracts Involved in Energy Trading and Risk Management Activities” (EITF 98-10). As a result, energy-related contracts that are not accounted for pursuant to Statement 133 are no longer carried at fair value, but rather will be accounted for on an accrual basis as executory contracts. As a result of the rescission of EITF 98-10, the Task Force also agreed that energy trading inventories carried under storage agreements should no longer be carried at fair value, but should be carried at the lower of cost or market. The rescission was effective for all fiscal periods beginning after December 31, 2002, and for all existing energy trading contracts and inventory as of October 25, 2002. Additionally, the rescission applied immediately to contracts entered into on or after October 25, 2002. Changes to the accounting for existing contracts as a result of the rescission of EITF 98-10 were reported as a cumulative effect of a change in accounting principle on January 1, 2003. This resulted in a cumulative effect loss, net of tax, of $141.8 million in 2003. The impact of this change was non-cash.

See Note D for more discussion of derivatives and risk management activities.

Impairment of Goodwill and Long-Lived Assets - We assess our goodwill for impairment at least annually based on Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets" (Statement 142). An initial assessment is made by comparing the fair value of the operations with goodwill, as determined in accordance with Statement 142, to the book value of each reporting unit. If the fair value is less than the book value, an impairment is indicated, and we must perform a second test to measure the amount of the impairment. In the second test, we calculate the implied fair value of the goodwill by deducting the fair value of all tangible and intangible net assets of the operations with goodwill from the fair value determined in step one of the assessment. If the carrying value of the goodwill exceeds this calculated implied fair value of the goodwill, we will record an impairment charge. See Note E for more discussion of goodwill.

We assess our long-lived assets for impairment based on Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (Statement 144). A long-lived asset is tested for impairment whenever events or changes in circumstances indicate that its carrying amount may exceed its fair value. Fair values are based on the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the assets.

Examples of long-lived asset impairment indicators include:
- a significant decrease in the market price of a long-lived asset or asset group,
- a significant adverse change in the extent or manner in which a long-lived asset or asset group is being used or in its physical condition,
- a significant adverse change in legal factors or in the business climate that could affect the value of a long-lived asset or asset group, including an adverse action or assessment by a regulator that would exclude allowable costs from the rate-making process,
- an accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of a long-lived asset or asset group,
- a current-period operating cash flow loss, combined with a history of operating cash flow losses or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset or asset group, and
- a current expectation that, more likely than not, a long-lived asset or asset group will be sold or otherwise disposed of significantly before the end of its previously estimated useful life.

In the third quarter of 2005, we made the decision to sell our Spring Creek power plant, located in central Oklahoma, and exit the power generation business. In October 2005, we concluded that our Spring Creek power plant had been impaired and recorded an impairment expense of $52.2 million. This conclusion was based on our Statement 144 impairment analysis of the results of operations for this plant through September 30, 2005, and also the net sales proceeds from the anticipated sale of the plant. These assets were held for sale at December 31, 2005, and, accordingly, this component of our business is accounted for as discontinued operations in accordance with Statement 144.

Pension and Postretirement Employee Benefits - We have a defined benefit pension plan covering substantially all full-time employees and a postretirement employee benefits plan covering most employees. Nonbargaining unit employees hired after December 31, 2004, are not eligible for our defined benefit pension plan; however, they are covered by a profit sharing plan. Our actuarial consultant calculates the expense and liability related to these plans and uses statistical and other factors that attempt to anticipate future events. These factors include assumptions about the discount rate, expected return on plan assets, rate of future compensation increases, age and employment periods. In determining the projected benefit obligations and the costs, assumptions can change from period to period and result in material changes in the costs and liabilities we recognize. See Note J for more discussion of pension and postretirement employee benefits.

The FASB is currently reviewing the accounting for pension and postretirement medical benefits and expects to issue an exposure draft on phase one of this project during the first quarter of 2006. The final standard for the first phase of this project is expected to be issued in the third quarter of 2006 with implementation required for years ending after December 15, 2006. Based on the FASB's discussion, we could be required to record a balance sheet liability equal to the difference between our benefit obligation and plan assets. If this requirement had been in place at December 31, 2005, we would have been required to record unrecognized losses of $124.8 million and $78.8 million for pension and postretirement benefits, respectively, on our consolidated balance sheet as accumulated other comprehensive income (loss).

Contingencies - Our accounting for contingencies covers a variety of business activities including contingencies for legal exposures and environmental exposures. We accrue these contingencies when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered and an amount can be reasonably estimated in accordance with Statement of Financial Accounting Standards No. 5, "Accounting for Contingencies." We base our estimates on currently available facts and our estimates of the ultimate outcome or resolution. Actual results may differ from our estimates resulting in an impact, either positive or negative, on earnings. See Note K for more discussion of contingencies.

Significant Accounting Policies

Consolidation - The consolidated financial statements include the accounts of ONEOK, Inc. and its wholly-owned subsidiaries. All significant intercompany accounts and transactions have been eliminated in consolidation. Investments in 20 percent to 50 percent-owned affiliates are accounted for on the equity method. Investments in less than 20 percent owned affiliates are accounted for on the cost method unless we have the ability to exercise significant influence over operating and financial policies of our investee, in which case we apply the equity method. Our investment in the general and limited partner interests in Northern Border Partners is accounted for by the equity method.

In June 2005, the FASB ratified the consensus reached in EITF Issue No. 04-5, "Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights" (EITF 04-5). EITF 04-5 presumes that a general partner controls a limited partnership and therefore should consolidate the partnership in the financial statements of the general partner. Effective January 1, 2006, we were required to consolidate Northern Border Partners' operations in our consolidated financial statements and we elected to use the prospective method. If we had consolidated Northern Border Partners at December 31, 2005, our debt-to-equity ratio would have changed from 67 percent debt and 33 percent equity to 73 percent debt and 27 percent equity. This increase results from the consolidation of Northern Border Partners' debt of $1.35 billion at December 31, 2005, while the majority of their equity is reported as minority interest liability. The debt covenant calculations in our credit agreements exclude the debt of Northern Border Partners since it is a master limited partnership. The adoption of EITF 04-5 will not have an impact on our net income; however, reported revenues, costs and expenses will be higher to reflect the activities of Northern Border Partners.

Cash and Cash Equivalents - Cash equivalents consist of highly liquid investments, which are readily convertible into cash and have original maturities of three months or less.

Inventories - Materials and supplies are valued at average cost. Noncurrent natural gas in storage is classified as property and is valued at cost. Cost of current natural gas in storage for Oklahoma Natural Gas is determined under the last-in, first-out (LIFO) methodology. The estimated replacement cost of current natural gas in storage was $70.2 million and $37.3 million at December 31, 2005 and 2004, respectively, compared to its value under the LIFO method of $56.2 million and $38.9 million at December 31, 2005 and 2004, respectively. Current natural gas and NGLs in storage for all other companies are determined using the weighted average cost method.

In September 2005, the FASB ratified the consensus reached in EITF Issue No. 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty" (EITF 04-13). EITF 04-13 defines when a purchase and a sale of inventory with the same party that operates in the same line of business should be considered a single nonmonetary transaction. EITF 04-13 is effective for new arrangements that a company enters into in periods beginning after March 15, 2006. We do not expect the adoption of EITF 04-13 to impact our consolidated financial statements.

Property - The following table sets forth property, by segment, for the periods presented.

	Years Ended December 31,	
	2005	**2004**
	(Thousands of dollars)	
Gathering and Processing	**$ 778,022**	$1,034,344
Natural Gas Liquids	**497,836**	32,268
Pipelines and Storage	**1,136,821**	705,115
Energy Services	**7,690**	7,531
Distribution	**3,016,668**	2,916,440
Other	**138,328**	137,178
Property, plant and equipment	**5,575,365**	4,832,876
Accumulated depreciation, depletion and amortization	**1,581,138**	1,519,719
Net property, plant and equipment	**$3,994,227**	$3,313,157

Regulated Property - Regulated properties are stated at cost, which includes an allowance for funds used during construction. The allowance for funds used during construction represents the capitalization of the estimated average cost of borrowed funds (5.9 percent in 2005 and 6.2 percent in 2004) used during the construction of major projects and is recorded as a credit to interest expense. Depreciation is calculated using the straight-line method based on rates prescribed for ratemaking purposes. The average depreciation rates for Oklahoma Natural Gas and ONEOK Gas Transportation property regulated by the Oklahoma Corporation Commission (OCC), Kansas Gas Service and Mid Continent Market Center property regulated by the Kansas Corporation Commission (KCC), Texas Gas Service and ONEOK WesTex Transmission property regulated by the Texas Railroad Commission (RRC) and various municipalities in Texas, and ONEOK NGL Pipeline property regulated by the Federal Energy Regulatory Commission (FERC) is set forth in the following table for the periods indicated.

	Years Ended December 31,		
Regulated Property	**2005**	**2004**	**2003**
Oklahoma Natural Gas	**2.8%**	2.9%	2.8%
Kansas Gas Service	**3.3%**	3.2%	3.3%
Texas Gas Service	**3.1%**	3.2%	3.2%
ONEOK Gas Transportation	**2.1%**	2.1%	2.1%
Mid-Continent Market Center	**3.6%**	3.6%	3.5%
ONEOK WesTex Transmission	**2.2%**	2.2%	2.1%
ONEOK NGL Pipeline	**2.7%**	(a)	(a)

(a) In July 2005, we acquired the natural gas liquids businesses from Koch.

Maintenance and repairs are charged directly to expense. Generally, the cost of property retired or sold, plus removal costs, less salvage, is charged to accumulated depreciation. Gains and losses from sales or transfers of operating units or systems are recognized in income.

The following table sets forth the remaining life and service years of our regulated properties.

	Remaining Life	**Service Years**
Distribution property	18-25	39-47
Transmission property	18-36	40-49
Other property	7-15	15-25

Other Property - Gas processing plants and all other properties are stated at cost. Gas processing and natural gas liquids fractionation plants are depreciated using various rates based on estimated lives of available natural gas reserves. All other property and equipment are depreciated using the straight-line method over its estimated useful life.

Environmental Expenditures - We accrue for losses associated with environmental remediation obligations when such losses are probable and reasonably estimable. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than completion of the remedial feasibility study. Such accruals are adjusted as further information becomes available or circumstances change. Recoveries of environmental remediation costs from other parties are recorded as assets when their receipt is deemed probable.

Revenue Recognition - We recognize revenue when services are rendered or product is delivered. Major industrial and commercial natural gas distribution customers are invoiced as of the end of each month. Certain natural gas distribution customers, primarily residential and some commercial are invoiced on a cyclical basis throughout the month, and we accrue unbilled revenues at the end of each month. Tariff rates for residential and commercial Oklahoma Natural Gas, Kansas Gas Service and some Texas Gas Service customers contain a temperature normalization clause that provides for billing adjustments from actual volumes to normalized volumes during the winter heating season. A flat monthly service fee is included in the authorized rate design for Texas Gas Service in El Paso and Port Arthur to protect customers from abnormal rate fluctuations due to weather.

Income Taxes - Deferred income taxes are recognized for the tax consequences of temporary differences by applying enacted statutory tax rates applicable to future years to differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities. The effect on deferred taxes of a change in tax rates is deferred and amortized for operations regulated by the OCC, KCC, RRC and various municipalities in Texas. For all other operations the effect is recognized in income in the period that includes the enactment date. We continue to amortize previously deferred investment tax credits for ratemaking purposes over the period prescribed by the OCC, KCC, RRC and various municipalities in Texas.

Regulation - Our intrastate natural gas transmission pipelines and distribution operations are subject to the rate regulation and accounting requirements of the OCC, KCC, RRC and various municipalities in Texas. Other transportation activities are subject to regulation by the FERC. Oklahoma Natural Gas, Kansas Gas Service, Texas Gas Service and portions of our Pipelines and Storage segment follow the accounting and reporting guidance contained in Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation" (Statement 71). During the rate-making process, regulatory authorities may require us to defer recognition of certain costs to be recovered through rates over time as opposed to expensing such costs as incurred. This allows us to stabilize rates over time rather than passing such costs on to the customer for immediate recovery. Accordingly, actions of the regulatory authorities could have an affect on the amount recovered from rate payers. Any difference in the amount recoverable and the amount deferred would be recorded as income or expense at the time of the regulatory action. If all or a portion of the regulated operations becomes no longer subject to the provisions of Statement 71, a write-off of regulatory assets and stranded costs may be required.

At December 31, 2005, we had regulatory assets in the amount of $181.7 million, included in investments and other in our Consolidated Balance Sheets. Regulatory assets are being recovered through various rate cases with the exception of an immaterial amount, which we expect to eventually recover.

Asset Retirement Obligations - In March 2005, the FASB issued Interpretation No. 47, “Accounting for Conditional Asset Retirement Obligations” (FIN 47), that requires an entity to recognize a liability for the fair value of a conditional asset retirement obligation when incurred if the liability’s fair value can be reasonably estimated. FIN 47 is effective for our year ended December 31, 2005. We completed our review of the applicability of FIN 47 to our operations and determined that the impact was immaterial to our consolidated financial statements.

On January 1, 2003, we adopted Statement of Financial Accounting Standards No. 143, “Accounting for Asset Retirement Obligations” (Statement 143). Statement 143 applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset. Statement 143 requires that we recognize the fair value of a liability for an asset retirement obligation in the period when it is incurred if a reasonable estimate of the fair value can be made. The fair value of the liability is added to the carrying amount of the associated asset and this additional carrying amount is depreciated over the life of the asset. The liability is accreted at the end of each period through charges to operating expense. If the obligation is settled for an amount other than the carrying amount of the liability, we will recognize a gain or loss on settlement.

All legal obligations for asset retirement obligations were identified and the fair value of these obligations was determined as of January 1, 2003. The obligations primarily relate to the 300-megawatt power plant and various processing plants, storage facilities and producing wells. As a result of the adoption of Statement 143, we recorded a long-term liability of approximately $16.3 million, an increase to property, plant and equipment, net of accumulated depreciation, of approximately $12.9 million, and a cumulative effect loss of approximately $2.1 million, net of tax, in the first quarter of 2003. The related depreciation and amortization expense is immaterial to our consolidated financial statements.

In accordance with long-standing regulatory treatment, we collect through rates the estimated costs of removal on certain regulated properties through depreciation expense, with a corresponding credit to accumulated depreciation, depletion and amortization. These removal costs are non-legal obligations as defined by Statement 143. However, these non-legal asset removal obligations should be accounted for as a regulatory liability under Statement 71. Historically, the regulatory authorities which have jurisdiction over our regulated operations have not required us to track this amount; rather these costs are addressed prospectively as depreciation rates are set in each general rate order. We have made an estimate of our removal cost liability using current rates since the last general rate order in each of our jurisdictions. However, significant uncertainty exists regarding the ultimate determination of this liability pending, among other issues, clarification of regulatory intent. We continue to monitor the regulatory authorities and the liability may be adjusted as more information is obtained. We have reclassified the estimated non-legal asset removal obligation from accumulated deprecation, depletion and amortization to non-current liabilities in other deferred credits on our balance sheets as of December 31, 2005 and 2004. To the extent this estimated liability is adjusted, such amounts will be reclassified between accumulated depreciation, depletion and amortization and other deferred credits and thus will not have an impact on earnings.

Common Stock Options and Awards - In December 2004, the FASB issued Statement of Financial Accounting Standards No. 123R, "Share-Based Payment" (Statement 123R). Statement 123R requires companies to expense the fair value of share-based payments. In addition, there are also changes related to the expense calculation for share-based payments. Effective January 1, 2006, we adopted Statement 123R, and we elected to use the prospective method. We are currently assessing the impact of adopting Statement 123R, but we do not believe it will have a material impact on our financial condition and results of operations, as we have been expensing share-based payments since our adoption of Statement of Financial Accounting Standards No. 148, "Accounting for Stock-Based Compensation - Transition and Disclosure" (Statement 148) on January 1, 2003.

On January 1, 2003, we adopted Statement 148, which was an amendment to Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation" (Statement 123). We elected to begin expensing the fair value of all stock option compensation granted on or after January 1, 2003 under the prospective method allowed by Statement 148. Prior to January 1, 2003, we accounted for our stock option compensation under the recognition and measurement principles of APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations.

The following table sets forth the effect on net income and earnings per common share (EPS) as if we had applied the fair-value recognition provisions of Statement 123 to stock-based employee compensation in the periods presented.

	Years Ended December 31,		
	2005	**2004**	**2003**
	(Thousands of dollars, except per share amounts)		
Net income, as reported	**$546,545**	$242,178	$112,488
Add: Stock option compensation included in net income, net of related tax effects	**8,343**	9,228	4,650
Deduct: Total stock option compensation expense determined under fair value based method for all awards, net of related tax effects	**8,994**	10,415	5,864
Pro forma net income	**$545,894**	$240,991	$111,274
Earnings per share:			
Basic - as reported	**$ 5.44**	$ 2.38	$ 1.48
Basic - pro forma	**$ 5.43**	$ 2.36	$ 1.46
Diluted - as reported	**$ 5.06**	$ 2.30	$ 1.22
Diluted - pro forma	**$ 5.05**	$ 2.29	$ 1.21

Earnings per Common Share - Basic EPS is calculated based on the daily weighted average number of shares of common stock outstanding during the period. Diluted EPS is calculated based on the daily weighted average number of shares of common stock outstanding during the period plus potentially dilutive components. The dilutive components are calculated based on the dilutive effect for each quarter. For any fiscal year period consisting of two or more quarters, the dilutive components for each quarter are averaged to arrive at the fiscal year-to-date dilutive component.

Labor Force - We employed 4,559 people at December 31, 2005. Approximately 17 percent of the workforce, all of whom are employed by Kansas Gas Service, is covered by collective bargaining agreements, with 7 percent covered by agreements that expire in 2006 and 10 percent covered by agreements that expire in 2009.

Use of Estimates - Certain amounts included in or affecting our financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions which cannot be known with certainty at the time the financial statements are prepared. Items which may be estimated include, but are not limited to, the economic useful life of assets, fair value of assets and liabilities, obligations under employee benefit plans, provisions for uncollectible accounts receivable, unbilled revenues for natural gas delivered but for which meters have not been read, gas purchased expense for natural gas received but for which no invoice has been received, provision for income taxes including any deferred tax valuation allowances, the results of litigation and various other recorded or disclosed amounts. Accordingly, the reported amounts of our assets and liabilities, revenues and expenses, and related disclosures are necessarily affected by these estimates.

We evaluate these estimates on an ongoing basis using historical experience, consultation with experts and other methods we consider reasonable based on the particular circumstances. Nevertheless, actual results may differ significantly from the estimates. Any effects on our financial position or results of operations from revisions to these estimates are recorded in the period when the facts that give rise to the revision become known.

Reclassifications and Revisions - Certain amounts in prior period consolidated financial statements have been reclassified to conform to the 2005 presentation. These reclassifications did not impact previously reported net income or shareholders' equity.

In 2005, we combined cash flows from discontinued operations with cash flows from continuing operations to present cash flows on a combined basis in our consolidated statements of cash flows. The consolidated statements of cash flows have been revised for 2003 to conform to the 2005 presentation and to reconcile from net income instead of income from continuing operations.

Prior periods have been adjusted to reflect the sale of our Production segment and the pending sale of our Spring Creek power plant as discontinued operations. See Note C for additional information.

B. ACQUISITIONS AND DIVESTITURES

In December 2005, we sold our natural gas gathering and processing assets located in Texas to a subsidiary of Eagle Rock Energy, Inc. for approximately $527.2 million and recorded a pre-tax gain of $264.2 million, which is included in gain on sale of assets in our operating income. The gain reflects the cash received less adjustments, selling expenses and the net book value of the assets sold.

In October 2005, we entered into an agreement to sell our Spring Creek power plant to Westar Energy, Inc. for $53 million. The transaction requires FERC approval and is expected to be completed in 2006. The 300-megawatt gas-fired merchant power plant was built in 2001 to supply electrical power during peak periods using gas-powered turbine generators. The financial information related to the properties sold is reflected as a discontinued component in our consolidated financial statements. All periods presented have been restated to reflect the discontinued component. See Note C for additional information.

In September 2005, we completed the sale of our Production segment to TXOK Acquisition, Inc. for $645 million, before adjustments and recognized a pre-tax gain on the sale of approximately $240.3 million. The gain reflects the cash received less adjustments, selling expenses and the net book value of the assets sold. The proceeds from the sale were used to reduce debt. The financial information related to the properties sold is reflected as a discontinued component in our consolidated financial statements. All periods presented have been restated to reflect the discontinued component. See Note C for additional information.

In July 2005, we completed the acquisition of the natural gas liquids businesses owned by several affiliates and a subsidiary of Koch Industries, Inc. (Koch) for approximately $1.33 billion, net of working capital and cash received. This transaction included Koch Hydrocarbon, LP's entire mid-continent natural gas liquids fractionation business; Koch Pipeline Company, LP's natural gas liquids pipeline distribution systems; Chisholm Pipeline Holdings, Inc., which has a 50 percent ownership interest in Chisholm Pipeline Company; MBFF, LP, which owns an 80 percent interest in a 160,000 barrel per day fractionator at Mont Belvieu, Texas; and Koch Vesco Holdings, LLC, an entity that owns a 10.2 percent interest in Venice

Energy Services Company, LLC (VESCO). These assets are included in our consolidated financial statements beginning on July 1, 2005.

The unaudited pro forma information in the table below presents a summary of our consolidated results of operations as if the acquisition of the Koch natural gas liquids businesses had occurred at the beginning of the periods presented. The results do not necessarily reflect the results that would have been obtained if the acquisition had actually occurred on the dates indicated or results that may be expected in the future.

	Pro Forma Years Ended December 31,	
	2005	**2004**
	(Thousand of Dollars, except per share amounts)	
Revenues	**$ 12,782,367**	$ 5,978,946
Net income	**$ 550,997**	$ 256,569
Net earnings per share, basic	**$ 5.48**	$ 2.52
Net earnings per share, diluted	**$ 5.10**	$ 2.43

The acquisition increased our mid-continent operating focus through a downstream extension of our natural gas gathering and processing operation. The assets acquired provide commercial, operational and administrative synergies as these assets enhance our existing mid-stream operating areas. This acquisition creates new and expanded commercial opportunities and we anticipate volumes and margins of our existing business to increase. Our gathering and processing assets are the second largest producer of NGLs on the natural gas liquids pipeline, storage and fractionation system and all but two of our processing plants are connected to this system. Additionally, the acquisition improves our market access to the largest NGL hub, which is located in the gulf coast. As a result of our purchase price allocation, we assigned $1.2 billion to identifiable assets consisting of approximately $928.9 million to tangible assets based on the fair value of the net assets and approximately $306.7 million to identifiable intangible assets, primarily contracts acquired, that will be amortized on a straight-line basis over an aggregated weighted average period of 40 years. The excess of the purchase price over the fair value of identifiable assets acquired, net of liabilities assumed is $173.9 million, which is recorded as goodwill. This entire amount of goodwill is deductible for tax purposes.

The purchase price and related allocation are preliminary and may be revised as a result of adjustments made to the purchase price, additional information regarding liabilities assumed, including contingent liabilities, and revisions of preliminary estimates of fair values made at the date of purchase. The pro forma balance sheet as of the acquisition date is shown below.

	July 1, 2005
Assets	*(Thousands of dollars)*
Current assets	**$ 106,634**
Property, plant and equipment, net	**879,943**
Goodwill and intangibles	**480,595**
Investments and other	**49,000**
Total Assets	**$ 1,516,172**
Liabilities	
Accounts payable	**$ 172,941**
Other current liabilities	**15,665**
Total Liabilities	**$ 188,606**
Net Assets Acquired	**$ 1,327,566**

In November 2004, we acquired Northern Plains, which owns 82.5 percent of the general partner interest and 500,000 limited partnership units, together representing a 2.73 percent ownership interest, in Northern Border Partners, from CCE Holdings, LLC for $175 million.

In 2004, we sold other assets including natural gas transmission and gathering pipelines, compression facilities, propane operations and a gas distribution system for approximately $20.4 million and recorded a pre-tax gain of $10.4 million.

In December 2003, we acquired approximately $240 million of natural gas and crude oil properties and related flow lines located in Texas. The results of operations for these assets were included in our consolidated financial statements from that date until the disposition of our Production segment in September 2005.

We also acquired other assets during 2003, including NGL storage and pipeline facilities and a gas distribution system, totaling approximately $19.7 million.

In October 2003, we sold our Texas transmission assets for approximately $3.1 million. We recorded a charge against accumulated depreciation of approximately $7.8 million in accordance with Statement 71 and the regulatory accounting requirements of the FERC and RRC.

In January 2003, we sold approximately 70 percent of the natural gas and crude oil producing properties of our Production segment for a cash sales price of $294 million, including adjustments. See Note C for additional information.

In January 2003, we acquired the Texas natural gas distribution business and other assets from Southern Union Company. The results of operations for these assets have been included in our consolidated financial statements since that date. We paid approximately $436.6 million for these assets, including $16.6 million in working capital adjustments. The primary assets acquired were natural gas distribution operations that currently serve approximately 560,000 customers in cities located throughout Texas, including the major cities of El Paso and Austin, as well as the cities of Port Arthur, Galveston, Brownsville and others. Over 90 percent of the customers are residential. The other assets acquired include a 125-mile natural gas transmission system, as well as other energy related domestic assets involved in natural gas marketing, retail sales of propane and distribution of propane. The purchase also included natural gas distribution investments in Mexico. The assets relating to the propane distribution operations were sold in May and July 2004 and the natural gas distribution investments in Mexico were sold in May 2004.

C. DISCONTINUED OPERATIONS

In September 2005, we completed the sale of our Production segment to TXOK Acquisition, Inc. for $645 million, before adjustments, and recognized a pre-tax gain on the sale of approximately $240.3 million. The gain reflects the cash received less adjustments, selling expenses and the net book value of the assets sold. The proceeds from the sale were used to reduce debt. Our Board of Directors had approved the potential sale in July 2005, which resulted in our Production segment being classified as held for sale beginning July 1, 2005. In accordance with Statement 144, we did not record any depreciation, depletion or amortization for our Production segment while it was classified as held for sale.

Additionally, in the third quarter of 2005, we made the decision to sell our Spring Creek power plant and exit the power generation business. We entered into an agreement to sell our Spring Creek power plant to Westar Energy, Inc. for $53 million. The transaction requires FERC approval and is expected to be completed in 2006. The 300-megawatt gas-fired merchant power plant was built in 2001 to supply electrical power during peak periods using gas-powered turbine generators. The proceeds from this sale will be used to purchase other assets, repurchase ONEOK shares or retire debt.

In January 2003, we sold approximately 70 percent of the natural gas and crude oil producing properties of our Production segment for an adjusted cash price of $294 million. The properties sold were located in Oklahoma, Kansas and Texas. We recorded a pretax gain of approximately $61.2 million in 2003 related to this sale. The gain reflects the cash received less adjustments, selling expenses and the net book value of the assets sold.

These components of our business are accounted for as discontinued operations in accordance with Statement 144. Accordingly, amounts in our financial statements and related notes for all periods shown relating to our Production segment and our power generation business are reflected as discontinued operations.

The amounts of revenue, costs and income taxes reported in discontinued operations are as follows.

	Years Ended December 31,		
	2005	**2004**	**2003**
	(Thousands of dollars)		
Operating revenues	**$ 135,213**	$ 202,552	$ 136,271
Cost of sales and fuel	**38,398**	95,524	76,870
Net margin	**96,815**	107,028	59,401
Impairment expense	**52,226**	-	-
Operating costs	**24,302**	29,997	19,270
Depreciation, depletion and amortization	**17,919**	30,673	18,103
Operating income	**2,368**	46,358	22,028
Other income (expense), net	**252**	60	10
Interest expense	**12,588**	16,167	5,953
Income taxes	**(3,788)**	12,746	5,900
Income (loss) from operations of discontinued components, net	**$ (6,180)**	$ 17,505	$ 10,185
Gain on sale of discontinued components, net of tax of $90.7 million, $0 million and $21.5 million, respectively	**$ 149,577**	$ -	$ 39,739

The following table discloses the major classes of discontinued assets and liabilities included in our Consolidated Balance Sheets for the periods indicated.

	December 31, 2005	December 31, 2004
Assets	*(Thousands of dollars)*	
Trade accounts and notes receivable, net	**$ -**	$ 19,564
Energy marketing and risk management assets	**-**	1,891
Property, plant and equipment, net	**50,937**	473,664
Deferred income taxes	**9,151**	-
Investments and other	**3,823**	10,121
Assets of Discontinued Component	**$ 63,911**	$ 505,240
Liabilities		
Accounts payable	**$ 1,043**	$ 23,367
Energy marketing and risk management liabilities	**-**	6,007
Deferred income taxes	**-**	43,251
Other liabilities	**1,421**	13,550
Liabilities of Discontinued Component	**$ 2,464**	$ 86,175

D. ENERGY MARKETING AND RISK MANAGEMENT ACTIVITIES AND FAIR VALUE OF FINANCIAL INSTRUMENTS

Risk Policy and Oversight - Market risks are monitored by a risk control group that operates independently from the operating segments that create or actively manage these risk exposures. The risk control group ensures compliance with our risk management policies.

We control the scope of risk management, marketing and trading operations through a comprehensive set of policies and procedures involving senior levels of management. The audit committee of our Board of Directors has oversight responsibilities for our risk management limits and policies. Our risk oversight committee, comprised of corporate officers, oversees all activities related to commodity price, credit and interest rate risk management, and marketing and trading activities. The committee also proposes risk metrics including value-at-risk (VAR) and dollar loss limits. We have a corporate risk control organization led by our Senior Vice President of Financial Services and Treasurer and our Vice President of Audit and Risk Control, who are assigned responsibility for establishing and enforcing the policies, procedures and limits. Key risk control activities include credit review and approval, credit and performance risk measurement and monitoring, validation of transactions, portfolio valuation, VAR and other risk metrics.

To the extent open commodity positions exist, fluctuating commodity prices can impact our financial results and financial position, either favorably or unfavorably. As a result, we cannot predict with precision the impact risk management decisions may have on our business, operating results or financial position.

Accounting Treatment - We account for derivative instruments and hedging activities in accordance with Statement 133. Under Statement 133, entities are required to record all derivative instruments at fair value. The accounting for changes in the fair value of a derivative instrument depends on whether it has been designated and qualifies as part of a hedging relationship and, if so, the reason for holding it. If the derivative instrument does not qualify or is not designated as part of a hedging relationship, we account for changes in fair value of the derivative instrument in earnings as they occur. We record these changes in fair value as operating revenues in our Consolidated Statements of Income. If certain conditions are met, entities may elect to designate a derivative instrument as a hedge of exposure to changes in fair values, cash flows or foreign currencies. For hedges of exposure to changes in fair value, the gain or loss on the derivative instrument is recognized in earnings in the period of change together with the offsetting loss or gain on the hedged item attributable to the risk being hedged. The difference between the change in fair value of the derivative instrument and the change in fair value of the hedged item represents hedge ineffectiveness. For hedges of exposure to changes in cash flow, the effective portion of the gain or loss on the derivative instrument is reported initially as a component of other comprehensive income and is subsequently reclassified into earnings when the forecasted transaction affects earnings.

As required by Statement 133, we formally document all relationships between hedging instruments and hedged items, as well as risk management objectives, strategies for undertaking various hedge transactions and methods for assessing and testing correlation and hedge ineffectiveness. We specifically identify the asset, liability, firm commitment or forecasted transaction that has been designated as the hedged item. We assess the effectiveness of hedging relationships, both at the inception of the hedge and on an ongoing basis.

In July 2003, the EITF reached a consensus on EITF Issue No. 03-11, “Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not ‘Held for Trading Purposes’ as Defined in EITF Issue No. 02-3” (EITF 03-11). EITF 03-11 provides that the determination of whether realized gains and losses on physically settled derivative contracts not “held for trading purposes” should be reported in the income statement on a gross or net basis is a matter of judgment that depends on the relevant facts and circumstances. Consideration of the facts and circumstances should be made in the context of the various activities of the entity rather than based solely on the terms of the individual contracts.

At the beginning of the third quarter of 2004, we completed a reorganization of our Energy Services segment and renewed our focus on our physical marketing and storage business. We separated the management and operations of our wholesale marketing, retail marketing and trading activities and began accounting separately for the different types of revenue earned from these activities. Prior to the third quarter, we managed our Energy Services segment on an integrated basis and presented all energy trading activity on a net basis.

Concurrent with this reorganization, we evaluated the accounting treatment related to the presentation of revenues from the different types of activities to determine which amounts should be reported on a gross or net basis under the guidance in EITF 03-11. For derivative instruments considered held for trading purposes that result in physical delivery, the indicators in EITF Issue No. 02-3, “Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities” were used to determine the proper treatment. These activities and all financially settled derivative contracts will continue to be reported on a net basis.

For derivative instruments that are not considered “held for trading purposes” and that result in physical delivery, the indicators in EITF 03-11 and EITF Issue No. 99-19, “Reporting Revenue Gross as a Principal versus Net as an Agent” (EITF 99-19) were used to determine the proper treatment. We began accounting for the realized revenues and purchase costs of these contracts that result in physical delivery on a gross basis beginning with the third quarter of 2004. We apply the indicators in EITF 99-19 to determine the appropriate accounting treatment for non-derivative contracts that result in physical delivery. Derivatives that qualify for the normal purchase or sale exception as defined in Statement 133 are also reported on a gross basis. No prior periods have been adjusted for this change; therefore, comparisons to prior periods may not be meaningful. Reporting of these transactions on a gross basis did not impact operating income but resulted in an increase to revenues and cost of sales and fuel.

Energy Marketing and Risk Management Activities - Our operating results are affected by commodity price fluctuations. We routinely enter into derivative financial instruments to minimize the risk of commodity price fluctuations related to anticipated sales of natural gas and crude oil, purchase and sale commitments, fuel requirements, transportation and storage contracts, and natural gas and NGL inventories. We are also subject to the risk of interest rate fluctuations in the normal course of business. We manage interest rate risk through the use of fixed rate debt, floating rate debt and, at times, interest rate swaps.

Our Energy Services segment includes our wholesale and retail natural gas marketing and storage, retail and financial trading operations. Our Energy Services segment generally attempts to manage the commodity risk of our fixed-price physical purchase and sale commitments in terms of contract volumes and the timing of performance and delivery obligations through the use of derivative instruments. With respect to the net open positions that exist within our financial trading operations, fluctuating commodity market prices can impact our financial position and results of operations, either favorably or unfavorably. The net open positions are actively managed and the impact of the changing prices on our financial condition at a point in time is not necessarily indicative of the impact of price movements throughout the year.

Operating margins associated with our Gathering and Processing and Natural Gas Liquids segments' natural gas gathering, processing and fractionation activities are sensitive to changes in natural gas, condensate and NGL prices, principally as a result of contractual terms under which natural gas is processed and products are sold. We use physical forward sales and derivative instruments to secure a certain price for natural gas, condensate and NGL products.

Fair Value Hedges - During the first quarter of 2005, we terminated $400 million of our interest rate swap agreements and paid a net amount of $19.4 million, which included $20.2 million for the present value of future payments at the time of termination, less $0.8 million for interest rate savings through the termination of the swaps. During the first quarter of 2004, we terminated $670 million of our interest rate swap agreements and received $81.9 million. The net savings from the termination of these swaps is being recognized in interest expense over the terms of the debt instruments originally hedged. Net interest expense savings for 2005 for all terminated swaps was $7.7 million, and the remaining net savings for all terminated swaps will be recognized over the following periods:

2006	$6.8 million
2007	$6.6 million
2008	$6.6 million
2009	$5.6 million
2010	$5.5 million
Thereafter	$15.3 million

Currently, $340 million of fixed rate debt is swapped to floating. The floating rate debt is based on both the three- and six-month London InterBank Offered Rate (LIBOR). Based on the actual performance through December 31, 2005, the weighted average interest rate on the $340 million of debt was reduced from 6.44 percent to 5.55 percent. At December 31, 2005, we recorded a net liability of $7.3 million to recognize the interest rate swaps at fair value. Long-term debt was decreased by $7.3 million to recognize the change in the fair value of the related hedged liability. See Note I.

Our Energy Services segment uses basis swaps to hedge the fair value of certain firm transportation commitments. Net gains or losses from the fair value hedges are recorded to cost of sales and fuel. The ineffectiveness related to these hedges was not material in 2005, 2004 or 2003.

Cash Flow Hedges - Our Energy Services segment uses futures and basis swaps to hedge the cash flows associated with our anticipated purchases and sales of natural gas and cost of fuel used in transportation of gas. Accumulated other comprehensive loss at December 31, 2005, includes net losses of approximately $66.9 million, net of tax, related to these hedges that will be realized within the next 41 months, of which $28.9 million in net gains will be recognized in the next 12 months. Our Gathering and Processing and Natural Gas Liquids segments periodically enter into derivative instruments to hedge the cash flows associated with their exposure to changes in the price of natural gas, crude oil and NGLs. Accumulated other comprehensive loss at December 31, 2005, includes gains of approximately $0.8 million, net of tax, for the gathering and processing hedges and losses of approximately $0.1 million, net of tax, for the natural gas liquids hedges, both of which will be realized in the income statement within the next 12 months. In accordance with Statement 133, the actual losses that are reclassified into earnings will be based on the mark-to-market prices at the future contract settlement dates, along with the realization of the gains or losses on the related physical volumes, which are not reflected in the amounts above.

Net gains and losses related to the ineffective portion of our hedges are reclassified out of accumulated other comprehensive loss to operating revenues or cost of sales and fuel. Ineffectiveness related to these cash flow hedges was approximately $33.9 million, $12.3 million and $7.7 million in 2005, 2004 and 2003, respectively. Additionally, losses of approximately $4.6 million were recognized from accumulated other comprehensive loss in 2004, due to the discontinuance of cash flow hedge treatment on certain transactions since it was probable that the forecasted transactions would not occur. There were no losses in 2005 or 2003 due to the discontinuance of cash flow hedge treatment.

Fair Value - The following table represents the fair value of our energy marketing and risk management assets and liabilities for the periods indicated. The fair value is the carrying value for these instruments at December 31, 2005 and 2004.

	Years Ended December 31,			
	2005		2004	
	Assets	Liabilities	Assets	Liabilities
	(Thousands of dollars)			
Gathering and processing - cash flow hedges	**$ 975**	**$ 5,635**	$ 7,662	$ 4,353
Natural gas liquids - cash flow hedges	**-**	**192**	-	-
Energy services - cash flow hedges	**398,311**	**537,259**	188,111	210,702
Energy services - fair value hedges	**23,900**	**261,196**	15,540	12,779
Distribution - natural gas swaps	**8,122**	**-**	-	1,015
Interest rate swaps - fair value hedges	**-**	**7,271**	4,160	21,758
Financial trading and non-trading instruments	**483,875**	**446,092**	242,618	255,884
Total fair value	**$ 915,183**	**$ 1,257,645**	$ 458,091	$ 506,491

Our regulated businesses use derivative instruments from time to time. Gains or losses associated with these derivative instruments are included in and recoverable through the monthly Purchased Gas Adjustment (PGA). At December 31, 2005, Kansas Gas Service had derivative instruments in place to hedge the cost of natural gas purchases for 2.4 Bcf, which represents part of their gas purchase requirements for the 2005/2006 winter heating months.

Based on quarterly measurements, the average fair values during 2005 for financial trading and non-trading assets and liabilities were approximately $484.2 million and $473.6 million, respectively. For 2004, the amounts were $292.7 million and $324.3 million, respectively.

Fair value estimates consider the market in which the transactions are executed. We utilize third party references for pricing points from New York Mercantile Exchange (NYMEX) and third-party over-the-counter brokers to establish commodity pricing and volatility curves. We believe the reported transactions from these sources are the most reflective of current market prices. Fair values are subject to change based on valuation factors. The estimate of fair value includes an adjustment for the liquidation of the position in an orderly manner over a reasonable period of time under current market conditions. The fair value estimate also considers the risk of nonperformance based on credit considerations of the counterparty.

Credit Risk - We maintain credit policies with regard to our counterparties that we believe significantly minimize overall credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit ratings), collateral requirements under certain circumstances and the use of standardized agreements which allow for netting of positive and negative exposures associated with a single counterparty.

Our counterparties consist primarily of financial institutions, major energy companies, local distribution companies (LDCs), electric utilities, and commercial and industrial end-users. This concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions. Based on our policies, exposures, credit and other reserves, we do not anticipate a material adverse effect on our financial position or results of operations as a result of counterparty nonperformance.

Financial Instruments

The following table represents the carrying amounts and estimated fair values of our financial instruments, excluding energy marketing and risk management assets and liabilities, which are listed in the table above.

	December 31, 2005		December 31, 2004	
	Book Value	Approximate Fair Value	Book Value	Approximate Fair Value
	(Thousands of dollars)			
Assets				
Cash and cash equivalents	**$ 7,915**	**$ 7,915**	$ 9,458	$ 9,458
Accounts and notes receivable	**$ 2,202,895**	**$ 2,202,895**	$ 1,412,861	$ 1,412,861
Liabilities				
Notes payable	**$ 1,541,500**	**$ 1,541,500**	$ 644,000	$ 644,000
Accounts payable	**$ 1,756,307**	**$ 1,756,307**	$ 1,161,984	$ 1,161,984
Long-term debt	**$ 2,032,413**	**$ 2,079,420**	$ 1,886,243	$ 1,949,965

The fair value of cash and cash equivalents, accounts and notes receivable, accounts payable, and notes payable, approximate book value due to their short-term nature. The estimated fair value of long-term debt has been determined using quoted market prices of the same or similar issues, discounted cash flows, and/or rates currently available to us for debt with similar terms and remaining maturities.

E. GOODWILL AND INTANGIBLES

In July 2005, we acquired the natural gas liquids businesses owned by Koch for approximately $1.33 billion, net of working capital and cash received. See Note B for additional information regarding this acquisition.

We performed our annual test of goodwill as of January 1, 2005, and there was no impairment indicated. The following table reflects the changes in the carrying amount of goodwill for the periods indicated.

	Balance December 31, 2003	Goodwill Adjustments	Balance December 31, 2004	Goodwill Acquired	Goodwill Adjustments	Balance December 31, 2005
	(Thousands of dollars)					
Gathering and Processing	$ 34,343	$ -	$ 34,343	$ -	$ (18,739)	**$ 15,604**
Natural Gas Liquids	-	-	-	173,945	-	**173,945**
Pipelines and Storage	22,288	(252)	22,036	-	-	**22,036**
Energy Services	10,255	-	10,255	-	-	**10,255**
Distribution	158,729	(175)	158,554	-	-	**158,554**
Total Goodwill	$ 225,615	$ (427)	$ 225,188	$ 173,945	$ (18,739)	**$ 380,394**

The 2005 adjustment to goodwill resulted from the sale of our natural gas gathering and processing assets located in Texas by our Gathering and Processing segment in December 2005. The 2004 adjustments to goodwill resulted from the sale of the natural gas distribution system in Eagle Pass, Texas by our Distribution segment in December 2004 and from the sale of certain natural gas transmission and gathering pipelines and compression facilities by our Pipelines and Storage segment in March 2004.

Intangible assets primarily relate to contracts acquired through the acquisition of the natural gas liquids businesses from Koch and, based on the purchase price allocation, are being amortized over an aggregate weighted-average period of 40 years. The aggregate amortization expense for each of the next five years is estimated to be approximately $7.7 million. The following tables reflect the gross carrying amount and accumulated amortization of intangibles at December 31, 2005.

	Intangibles, gross	Accumulated Amortization	Intangibles, net
		(Thousands of dollars)	
Natural Gas Liquids	$ 292,000	$ 3,649	**$ 288,351**
Pipelines and Storage	14,650	184	**14,466**
Total Intangibles	$ 306,650	$ 3,833	**$ 302,817**

	Balance December 31, 2004	Amortization	Balance December 31, 2005
		(Thousands of dollars)	
Natural Gas Liquids	$ -	$ 3,649	**$ 3,649**
Pipelines and Storage	-	184	**184**
Accumulated amortization	$ -	$ 3,833	**$ 3,833**

F. COMPREHENSIVE INCOME

The table below gives an overview of comprehensive income for the periods indicated. The assumption of derivative instruments in the table below relates to the derivative instruments transferred to the buyer of our Production segment.

	Years Ended December 31, 2005		2004	
	(Thousands of dollars)			
Net income		**$ 546,545**		$ 242,178
Unrealized losses on derivative instruments	**$ (17,013)**		$ (29,680)	
Unrealized holding losses arising during the period	**(606)**		(227)	
Realized (gains) losses in net income	**(35,069)**		45,420	
Assumption of derivative instruments related to sale of discontinued component	**(18,915)**		-	
Minimum pension liability adjustment	**(5,677)**		(2,400)	
Other comprehensive income (loss) before taxes	**(77,280)**		13,113	
Income tax (expense) benefit on other comprehensive income (loss)	**29,880**		(5,078)	
Other comprehensive income (loss)		**$ (47,400)**		$ 8,035
Comprehensive income		**$ 499,145**		$ 250,213

Accumulated other comprehensive loss at December 31, 2005 and 2004, primarily includes unrealized gains and losses on derivative instruments and minimum pension liability adjustments.

G. CAPITAL STOCK

Series A Convertible Preferred Stock - We issued Series A Convertible Preferred Stock (Series A), par value $0.01 per share, at the time of the November 1997 transaction with Westar Energy, Inc. (formerly Western Resources, Inc.). On February 5, 2003, we repurchased from Westar Industries, a wholly-owned subsidiary of Westar Energy (collectively "Westar"), approximately 9 million shares (approximately 18.1 million shares of common stock equivalents) of our Series A. We exchanged the remaining Series A shares for 21.8 million shares of our newly-created Series D Convertible Preferred Stock (Series D). See further discussion in the Westar section of this Note. There are no shares of Series A currently outstanding.

Series B Convertible Preferred Stock - There are no shares of Series B Convertible Preferred Stock currently outstanding.

Series C Preferred Stock - Series C Preferred Stock (Series C) is designed to protect our shareholders from coercive or unfair takeover tactics. Holders of Series C are entitled to receive, in preference to the holders of ONEOK, Inc. Common Stock, quarterly dividends in an amount per share equal to the greater of $0.50 or, subject to adjustment, 100 times the aggregate per share amount of all cash dividends, and 100 times the aggregate per share amount (payable in kind) of all non-cash dividends. No Series C has been issued.

Series D Convertible Preferred Stock - In February 2003, we exchanged the remaining shares of Series A for 21.8 million shares of Series D. During 2003, Westar sold all its equity in us, including all of the shares of our common stock and our Series D, which converted to common stock when sold. See further discussion in the Westar section of this Note. The Series D were retired after Westar's sale.

Common Stock - At December 31, 2005, we had approximately 185 million shares of authorized and unreserved common stock available for issuance.

The Board of Directors has reserved 12.0 million shares of our common stock for the Direct Stock Purchase and Dividend Reinvestment Plan, of which 186,000 shares, 151,000 shares and 172,000 shares were issued in 2005, 2004 and 2003, respectively. We have reserved approximately 13.2 million shares for the Thrift Plan, less the number of shares issued to date under this plan.

In January 2005, our Board of Directors authorized a stock buy back program to repurchase up to 7.5 million shares of our common stock currently issued and outstanding. Our Board of Directors extended this program in November 2005, and authorized us to repurchase an additional 7.5 million shares of our common stock currently issued and outstanding. Shares are repurchased from time to time in open market transactions or through privately negotiated transactions at our discretion, subject to market conditions and other factors. The program will terminate in November 2007, unless extended by our Board of Directors. During 2005, we repurchased approximately 7.5 million shares of our common stock pursuant to this program.

Dividends - Quarterly dividends paid on our common stock for shareholders of record as of the close of business on January 31, 2005, May 2, 2005, July 29, 2005 and October 31, 2005, were $0.25 per share, $0.28 per share, $0.28 per share and $0.28 per share, respectively. Additionally, a quarterly dividend of $0.28 per share was declared in January 2006, payable in the first quarter.

2004 Common Stock Offering - During the first quarter of 2004, we sold 6.9 million shares of our common stock to an underwriter at $21.93 per share, resulting in proceeds to us, before expenses, of $151.3 million.

2003 Public Offerings - During the first quarter of 2003, we conducted public offerings of our common stock and equity units. In connection with these offerings, we issued a total of 13.8 million shares of our common stock at the public offering price of $17.19 per share, resulting in aggregate net proceeds to us, after underwriting discounts and commissions, of $16.524 per share, or $228 million. In addition, we issued a total of 16.1 million equity units at the public offering price of $25 per unit, resulting in aggregate net proceeds to us, after underwriting discounts and commissions, of $24.25 per equity unit, or $390.4 million. Each equity unit consisted of a stock purchase contract for the purchase of our common stock and, initially, a senior note described in Note I. On February 16, 2006, we successfully settled the 16.1 million equity units to 19.5 million shares of our common stock. Of this amount, 8.3 million shares were issued from treasury stock and approximately 11.2 million shares were newly issued. Holders of the equity units received 1.2119 shares of our common stock for each equity unit they owned. The number of shares that we issued for each stock purchase contract was determined based on our average closing price over the 20-trading day period ending on the third trading day prior to February 16, 2006. With the settlement, we received $402.4 million in cash, which was used to pay down our short-term bridge financing agreement.

Westar - On January 9, 2003, we entered into an agreement with Westar to repurchase a portion of the shares of our Series A held by Westar and to exchange Westar's remaining shares of Series A for newly-created shares of our $0.925 Series D. The Series A were convertible into two shares of common stock for each share of Series A, reflecting our two-for-one stock split in 2001, and the Series D were convertible into one share of common stock for each share of Series D. Some of the differences between the Series D and the Series A were (a) the Series D had a fixed quarterly cash dividend of 23.125 cents per share, (b) the Series D was redeemable by us at any time after August 1, 2006, at a per share redemption price of $20, in the event that the per share closing price of our common stock exceeded, at any time prior to the date the notice of redemption was given, $25 for 30 consecutive trading days, (c) each share of Series D was convertible into one share of our common stock, and (d) with certain exceptions, Westar could not convert any shares of Series D held by it unless the annual per share dividend on our common stock for the previous year was greater than 92.5 cents and such conversion would not have subjected us to the Public Utility Holding Company Act of 1935.

In connection with that transaction, a new rights agreement, a new shareholder agreement and a new registration rights agreement between us and Westar became effective. The shareholder agreement restricted Westar from selling five percent or more of our outstanding Series D and common stock (assuming conversion of all shares of Series D to be transferred), in a bona fide public underwritten offering, to any one person or group. The agreement allowed Westar to sell up to five percent of our outstanding Series D and common stock (assuming conversion of all shares of Series D to be transferred) to any one person or group who did not own more than five percent of our outstanding common stock (assuming conversion of all shares of Series D to be transferred).

The KCC approved our agreement with Westar on January 17, 2003. On February 5, 2003, we consummated the agreement by purchasing $300 million of our Series A from Westar. We exchanged Westar's remaining 10.9 million Series A for approximately 21.8 million shares of our newly-created Series D. Upon the cash redemption of the Series A, the shares were converted to approximately 18.1 million shares of common stock in accordance with the terms of the Series A and the prior shareholder agreement with Westar. Accordingly, the redemption is reflected as an increase to common treasury stock. The Series D exchanged for the Series A was recorded at fair value and the premium over the previous carrying value of the Series A is reflected as a decrease in retained earnings. We had registered for resale all of the shares of our common stock held by Westar, as well as all the shares of our Series D issued to Westar and all of the shares of our common stock that were issuable upon conversion of the Series D.

On August 5, 2003, Westar conducted a secondary offering to the public of 9.5 million shares of our common stock at a public offering price of $19.00 per share, which resulted in gross offering proceeds to Westar of approximately $180.5 million. An over-allotment option for an additional 718,000 shares provided Westar with approximately $13.6 million. We did not receive any proceeds from the offering. Since Westar received in excess of $150 million of total proceeds from the offering, we were allowed, under a new transaction agreement related to the offering, to repurchase $50 million, or approximately 2.6 million shares, of our common stock from Westar at the public offering price of $19.00 per share. Our repurchase of those shares occurred immediately following the closing of the Westar offering. Of the shares sold in the Westar public offering, approximately 8.4 million shares represented our common stock issued by conversion of our Series D owned by Westar. The remaining shares consisted of approximately 1.1 million shares of our common stock owned by Westar.

On November 21, 2003, Westar sold its remaining equity in us, which included all the shares of common stock Westar owned and all of our Series D, which converted to shares of common stock when sold.

H. LINES OF CREDIT AND SHORT-TERM NOTES PAYABLE

General - The total amount of short-term borrowings authorized by our Board of Directors is $2.5 billion. At December 31, 2005, commercial paper and short-term notes payable totaling $1.54 billion were outstanding, which included $900.0 million of bridge financing for the Koch assets acquisition. Commercial paper and short-term notes payable totaling $644.0 million were outstanding at December 31, 2004. The commercial paper and short-term notes payable carried average interest rates of 3.73 percent and 1.77 percent for 2005 and 2004, respectively. We had $178.7 million and $3.6 million in letters of credit outstanding at December 31, 2005 and 2004, respectively.

Both the five-year credit agreement, which matures in 2009, and short-term bridge financing agreement contain customary affirmative and negative covenants, including covenants relating to liens, investments, fundamental changes in our business, changes in the nature of our business, transactions with affiliates, the use of proceeds, a limit on our debt-to-capital ratio, a limit on investments in master limited partnerships and a covenant that prevents us from restricting our subsidiaries' ability to pay dividends to ONEOK, Inc. In 2005, we amended the five-year credit and the short-term bridge financing agreements to change the definition of Consolidated Net Worth to eliminate the effect of gains and losses recorded in accumulated other comprehensive income (loss) as a result of certain commodity hedging agreements. At December 31, 2005, we were in compliance with all covenants.

Short-term Bridge Financing Agreement - In June 2005, we entered into a $1.0 billion short-term bridge financing agreement. The interest rate is based, at our election, on either (i) the higher of prime or one-half of one percent above the Federal Funds Rate, which is the rate that banks charge each other for the overnight borrowing of funds, or (ii) the Eurodollar rate plus a set number of basis points based on our current long-term unsecured debt ratings by Moody's Investors Service (Moody's) and Standard & Poor's Ratings Group (S&P).

On July 1, 2005, we borrowed $1.0 billion under the short-term bridge financing agreement to assist in financing the acquisition of assets from Koch. See Note B for additional information about this acquisition. We funded the remaining acquisition cost through our commercial paper program. We anticipate permanent financing of the acquisition to come from a combination of proceeds from the sale of assets, such as our Production segment and our Spring Creek power plant, proceeds from the February 2006 settlement of the purchase contracts that were part of our mandatory convertible equity units, and free cash flow. At December 31, 2005, we had lowered the balance of outstanding indebtedness under the bridge financing agreement to $900.0 million. The reduction in indebtedness under our short-term bridge financing agreement is a result of a required prepayment due to the sale of our Production segment. At our option, we paid $200.0 million on February 3, 2006. We paid an additional $403.0 million as a required prepayment on February 16, 2006, from the settlement of our equity units. The remaining balance of $297.0 million is required to be paid by March 31, 2006.

In November 2005, we amended the $1.0 billion short-term bridge financing agreement to remove the requirement to prepay the loan from any net cash proceeds received from the disposition of the natural gas gathering and processing assets located in Texas, provided that we prepay our 7.75 percent $300.0 million notes due in August 2006 in full, which we did in December 2005. See Note I for additional information regarding this prepayment.

Five-year Credit Agreement - In July 2005, we amended our 2004 $1.0 billion five-year credit agreement to increase the limit on our debt-to-capital ratio from 67.5 percent debt to 70.0 percent debt for the period from July 25, 2005, to February 28, 2006. Beginning on March 1, 2006, the limit on our debt will return to 67.5 percent of total capital.

In September 2005, we exercised the accordion feature of our 2004 $1.0 billion five-year credit agreement to increase the commitment amounts by $200 million to a total of $1.2 billion. The interest rate payable under this five-year credit agreement is a floating rate calculated in the same manner as the $1.0 billion short-term bridge financing agreement.

Uncommitted Line of Credit - We entered into an agreement with KBC Bank NV in April 2004. The agreement gives us access to an uncommitted line of credit for loans and letters of credit up to a maximum principal amount of $10 million. The rate charged on any outstanding amount is the higher of prime or one-half of one percent above the Federal Funds overnight rate, which is the rate that banks charge each other for the overnight borrowing of funds. This agreement remains in effect until canceled by KBC Bank NV or us. This agreement does not contain any covenants more restrictive than those in our $1.2 billion five-year credit agreement.

In December 2005, we amended our $10.0 million agreement with KBC Bank NV to increase the maximum principal amount available under the uncommitted line of credit to $15.0 million. The increased commitment was used to issue a $15.0 million standby letter of credit.

I. LONG-TERM DEBT

In November 2005, we elected for the early redemption of our 7.75 percent $300.0 million long-term notes with a stated maturity of August 2006. The early redemption occurred in December 2005, for a total payment of $314.4 million. In addition to the principal payment, we were required to pay a make-whole call premium of $5.7 million and accrued interest of $8.7 million. We funded this early redemption with the proceeds from the sale of our natural gas gathering and processing assets located in Texas.

In June 2005, we issued $800 million of notes, comprised of $400 million in 10-year maturities with a coupon of 5.2 percent and $400 million in 30-year maturities with a coupon of 6.0 percent. Proceeds from this debt issuance were used to repay commercial paper borrowings and for general corporate purposes.

In March 2005, we had $335 million of long-term debt mature. We funded payment of this debt with working capital and the issuance of commercial paper in the short-term market.

In the first quarter of 2003, we issued long-term debt concurrent with our public equity offering. We issued a total of 16.1 million equity units at the public offering price of $25 per unit, for a total of $402.5 million. Each equity unit consists of a stock purchase contract for the purchase of shares of our common stock and, initially, a senior note due February 16, 2008, issued pursuant to our existing Indenture with SunTrust Bank, as trustee. The equity units carry a total annual coupon rate of 8.5 percent (4.0 percent annual face amount of the senior notes plus 4.5 percent annual contract adjustment payments). The interest expense associated with the 4.0 percent senior notes will be recognized in the income statement on an accrual basis over the term of the senior notes. The present value of the contract adjustment payments was accrued as a liability with a charge to equity at the time of the transactions. Accordingly, there will be no impact on earnings in future periods as this liability is paid, except for the interest recognized as a result of discounting the liability to its present value at the time of the transaction. This interest expense associated with the discounting will be approximately $3.5 million over three years. In November 2005, we remarketed the notes with a new rate of 5.51 percent. The notes continue to have a stated maturity of February 2008. The cash received was put into a treasury portfolio pledged as collateral against the purchase contracts. We received this cash on February 16, 2006, when we successfully settled our equity units. See further discussion in Note G.

The following table sets forth our long-term debt for the periods indicated.

	December 31,	
	2005	**2004**
Long-term notes payable	*(Thousands of dollars)*	
7.75% due 2005	**$ -**	$ 335,000
7.75% due 2006	**-**	300,000
5.51%, 4.0% due 2008	**402,303**	402,500
LIBOR + 1.25% due 2009	**2,332**	2,694
6.0% due 2009	**100,000**	100,000
7.125% due 2011	**400,000**	400,000
7.25% due 2013	**2,044**	2,240
5.2% due 2015	**400,000**	-
6.4% due 2019	**92,921**	93,303
6.5% due 2028	**92,246**	92,395
6.875% due 2028	**100,000**	100,000
6.0% due 2035	**400,000**	-
8.0% due 2051	**1,356**	1,359
Total long-term notes payable	**1,993,202**	1,829,491
Change in fair value of hedged debt	**39,211**	56,752
Unamortized debt discount	**(1,796)**	(1,509)
Current maturities	**(6,547)**	(341,532)
Long-term debt	**$ 2,024,070**	$ 1,543,202

The aggregate maturities of long-term debt outstanding at December 31, 2005, are $6.5 million; $6.6 million; $408.9 million; $107.6 million; and $6.3 million for 2006 through 2010, respectively. Additionally, $185.1 million is callable at par at our option from now until maturity, which is 2019 for $92.9 million and 2028 for $92.2 million. All long-term debt is unsecured, with the exception of the $2.3 million note due in 2009. Certain debt agreements have negative covenants that relate to liens and sale/leaseback transactions.

J. EMPLOYEE BENEFIT PLANS

Retirement and Other Postretirement Benefit Plans

Retirement Plans - We have defined benefit and defined contribution retirement plans covering substantially all employees. Nonbargaining unit employees hired after December 31, 2004, are not eligible for our defined benefit pension plan; however, they are covered by a profit sharing plan. Certain officers and key employees are also eligible to participate in supplemental retirement plans. We generally fund pension costs at a level equal to the minimum amount required under the Employee Retirement Income Security Act of 1974.

We elected to delay recognition of the accumulated benefit obligation and amortize it over 20 years as a component of net periodic postretirement benefit cost. The accumulated benefit obligation for the defined benefit pension plan was $704.4 million and $681.3 million at December 31, 2005 and 2004, respectively.

Other Postretirement Benefit Plans - We sponsor welfare care plans that provide postretirement medical benefits and life insurance benefits to substantially all employees who retire under the retirement plans with at least five years of service. The postretirement medical plan is contributory, with retiree contributions adjusted periodically, and contains other cost-sharing features such as deductibles and coinsurance. Nonbargaining unit employees retiring between the ages of 50 and 55 who elect postretirement medical coverage, all nonbargaining unit employees hired on or after January 1, 1999, employees who are members of the International Brotherhood of Electrical Workers hired after June 30, 2003, and gas union employees hired after July 1, 2004, who elect postretirement medical coverage, pay 100 percent of the retiree premium for participation in the plan. Additionally, any employees who came to us through various acquisitions may be further limited in their eligibility to participate or receive any contributions from us for postretirement medical benefits.

In May 2004, the FASB issued FASB Staff Position No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" (FSP FAS 106-2) as guidance on how employers should account for provisions of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Reform Act). We adopted FSP FAS 106-2 in the second quarter of 2004. FSP FAS 106-2 superseded FASB Staff Position No. FAS 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," which we adopted in the first quarter of 2004. After careful analysis of the administrative requirements associated with the adoption of the Medicare Reform Act, we chose to carve out and discontinue prescription benefits for non-bargaining unit retirees. Non-bargaining unit retirees may qualify for medical insurance premium reimbursements from us. These reimbursements will be applied toward Medicare Part D and B premiums paid by the retiree. We have developed a wrap-around plan to be applied to the Medicare Part D program for bargaining unit retirees.

Measurement - We use a September 30 measurement date for the majority of our plans. In 2004, our plans were remeasured as of November 30 due to the Northern Plains acquisition. This remeasurement affected our pension and postretirement benefit expense beginning March 1, 2005.

Obligations and Funded Status - The following tables set forth our pension and other postretirement benefit plans benefit obligations, fair value of plan assets and funded status at December 31, 2005 and 2004.

	Pension Benefits December 31,		Postretirement Benefits December 31,	
	2005	**2004**	**2005**	**2004**
Change in Benefit Obligation	*(Thousands of dollars)*			
Benefit obligation, beginning of period	**$ 733,836**	$ 683,888	**$ 255,739**	$ 236,394
Service cost	**19,764**	15,834	**7,058**	5,954
Interest cost	**43,030**	41,916	**14,270**	13,587
Participant contributions	**-**	-	**2,355**	2,806
Plan amendments	**1,478**	2,890	**(22,433)**	3,254
Liability gain due to Medicare Reform	**-**	-	**-**	(24,039)
Actuarial loss	**21,335**	32,541	**12,910**	34,427
Acquisitions	**296**	-	**-**	-
Benefits paid	**(42,301)**	(43,233)	**(16,686)**	(16,644)
Benefit obligation, end of period	**$ 777,438**	$ 733,836	**$ 253,213**	$ 255,739
Change in Plan Assets				
Fair value of assets, beginning of period	**$ 660,299**	$ 613,872	**$ 46,229**	$ 39,168
Actual return on assets	**84,350**	82,821	**2,650**	4,821
Employer contributions	**1,513**	6,839	**2,231**	2,590
Benefits paid	**(42,301)**	(43,233)	**-**	-
Reimbursement	**-**	-	**-**	(350)
Fair value of assets, end of period	**$ 703,861**	$ 660,299	**$ 51,110**	$ 46,229
Funded status - under	**$ (73,577)**	$ (73,537)	**$ (202,103)**	$ (209,510)
Unrecognized net asset	**-**	-	**23,089**	28,398
Unrecognized prior service cost	**11,788**	11,753	**(15,451)**	5,600
Unrecognized net loss	**191,071**	202,586	**115,317**	107,065
Activity subsequent to measurement date	**-**	-	**5,232**	4,131
Prepaid (accrued) cost	**$ 129,282**	$ 140,802	**$ (73,916)**	$ (64,316)

Prepaid (accrued) cost for pension benefits includes a prepaid benefit of $146.7 million and a liability of $17.4 million at December 31, 2005. At December 31, 2004, the components of prepaid (accrued) cost for pension benefits included a prepaid benefit of $154.7 million and a liability of $13.9 million.

Components of Net Periodic Benefit Cost

The following tables set forth the components of net periodic benefit cost for our pension and other postretirement benefit plans for the periods indicated.

	Pension Benefits Years Ended December 31, 2005	2004	2003
Components of Net Periodic Benefit Cost (Income)	*(Thousands of dollars)*		
Service cost	**$ 19,764**	$ 15,834	$ 14,872
Interest cost	**43,030**	41,916	42,602
Expected return on assets	**(59,706)**	(60,165)	(64,264)
Amortization of unrecognized net asset at adoption	**-**	(314)	(467)
Amortization of unrecognized prior service cost	**1,443**	765	613
Amortization of loss	**8,502**	2,878	2,235
Net periodic benefit cost (income)	**$ 13,033**	$ 914	$ (4,409)

	Postretirement Benefits Years Ended December 31, 2005	2004	2003
Components of Net Periodic Benefit Cost	*(Thousands of dollars)*		
Service cost	**$ 7,058**	$ 5,954	$ 5,391
Interest cost	**14,270**	13,587	12,418
Expected return on assets	**(4,343)**	(3,811)	(3,154)
Amortization of unrecognized net transition obligation at adoption	**3,456**	3,456	3,456
Amortization of unrecognized prior service cost (income)	**471**	190	(125)
Amortization of loss	**6,469**	5,620	3,997
Net periodic benefit cost	**$ 27,381**	$ 24,996	$ 21,983

Actuarial Assumptions - The following table sets forth the weighted-average assumptions used to determine benefit obligations at December 31, 2005 and 2004.

	Pension Benefits December 31, 2005	2004	Postretirement Benefits December 31, 2005	2004
Discount rate	**5.75%**	6.00%	**5.75%**	6.00%
Compensation increase rate	**4.00%**	4.00%	**4.50%**	4.50%

The following table sets forth the weighted-average assumptions used to determine net periodic benefit costs at December 31, 2005 and 2004.

	Pension Benefits December 31, 2005	2004	Postretirement Benefits December 31, 2005	2004
Discount rate	**6.00%**	(a)	**6.00%**	(a)
Expected long-term return on plan assets	**8.75%**	8.75%	**8.75%**	8.75%
Compensation increase rate	**4.00%**	4.00%	**4.50%**	4.50%

(a) - The discount rate was 6.25% for the first nine months and 6.75% for the remaining three months of 2004.

Our overall expected long-term rate of return on plan assets assumption is an equally weighted blend of historical return, building block and economic growth/yield to maturity projections that we determined based on discussions with our independent investment consultants.

Our discount rates are based on our bond model analysis, where the amount and timing of the projected benefit payments are matched with the cash payments from coupons and maturities of a hypothetical bond portfolio. We first determined the projected cash flows for the plan for each year in the future. We projected these values based on the most recent valuation. The longest maturity period for bonds considered in our model is 30 years. Since cash flows are expected to continue beyond this period of time, we discount all benefit cash flows over 30 years back to the 30th year at a rate that is consistent with the yields on long-term zero coupon bonds. The resulting present value is treated as an additional benefit cash flow for the 30th year and handled the same way as any other benefit cash flow within our bond matching process. Our model uses the universe of bonds available at the measurement date with a quality rating of AA or better as rated by Moody's or S&P. Callable bonds are generally eliminated from the universe. A regression curve is generated for the expected yields from the remaining bonds. Any bonds with yields that fall outside a two standard deviation corridor are eliminated. Using the projected benefit cash flows and the bond universe defined above, our model considers all possible bond portfolios that produce matching cash flows and uses linear programming techniques to select the optimal portfolio with the highest possible yield. Our methodology is such that no single bond can comprise more than 15 percent of the total purchase. The model permits bond cash flows for a particular year to exceed the benefit cash flow for that year. The excess for a given year is used to meet the benefit cash flow in a future year and is reinvested at the one year forward rates.

Health Care Cost Trend Rates - The following table sets forth the assumed health care cost trend rates at December 31, 2005 and 2004.

	2005	**2004**
Health care cost trend rate assumed for next year	**9%**	10%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	**5%**	5%
Year that the rate reaches the ultimate trend rate	**2009**	2009

Assumed health care cost trend rates have a significant effect on the amounts reported for our health care plans. A one-percentage point change in assumed health care cost trend rates would have the following effects.

	One-Percentage Point Increase	**One-Percentage Point Decrease**
	(Thousands of dollars)	
Effect on total of service and interest cost	**$ 3,106**	**$ (2,513)**
Effect on postretirement benefit obligation	**$ 17,982**	**$ (15,619)**

Plan Assets - The following table sets forth our pension and postretirement benefit plan weighted-average asset allocations at December 31, 2005 and 2004.

	Pension Benefits		**Postretirement Benefits**	
	Percentage of Plan Assets at December 31,		**Percentage of Plan Assets at December 31,**	
Asset Category	**2005**	**2004**	**2005**	**2004**
U.S. equities	**57%**	57%	**65%**	68%
International equities	**13%**	11%	**13%**	12%
Investment grade bonds	**6%**	5%	**14%**	17%
High yield bonds	**9%**	9%	**0%**	0%
Cash and cash equivalents	**0%**	2%	**8%**	3%
Insurance contracts	**14%**	15%	**0%**	0%
Other	**1%**	1%	**0%**	0%
Total	**100%**	100%	**100%**	100%

Our investment strategy is to invest plan assets in accordance with sound investment practices that emphasize long-term investment fundamentals. The goal of this strategy is to maximize investment returns while managing risk in order to meet the plan's current and projected financial obligations. The plan's investments include a diverse blend of various U.S. and international equities, venture capital, investments in various classes of debt securities, and insurance contracts. The target allocation for the plan assets of our pension plan is as follows.

Corporate bonds / Insurance contracts	20%
High yield corporate bonds	10%
Large-cap value equities	16%
Large-cap growth equities	16%
Mid-cap equities	10%
Small-cap equities	10%
International equities	15%
Alternative investments	2%
Venture capital	1%

As part of our risk management for the plans, minimums and maximums have been set for each of the asset classes listed above. All investment managers for the plan are subject to certain restrictions on the securities they purchase and, with the exception of indexing purposes, are prohibited from owning our stock.

Contributions - For 2005, $1.5 million and $3.1 million of contributions were made to our pension plan and other postretirement benefit plan, respectively. We presently anticipate our total 2006 contributions will be $1.7 million for the pension plan and $2.7 million for the other postretirement benefit plan. Additionally, we expect our pay-as-you-go payments for the other postretirement benefit plan to be $14.0 million.

Pension and Other Postretirement Benefit Payments - The pension benefits expected to be paid in 2006-2010 are $43.5 million, $44.6 million, $45.6 million, $47.2 million and $47.8 million, respectively. The aggregate benefits expected to be paid in the five years from 2011-2015 are $258.5 million.

The other postretirement benefits expected to be paid in 2006-2010 are $14.0 million, $14.5 million, $15.0 million, $15.4 million and $16.2 million, respectively. The aggregate benefits expected to be paid in the five years from 2011-2015 are $91.9 million.

The expected benefits to be paid are based on the same assumptions used to measure our benefit obligation at December 31, 2005, and include estimated future employee service.

Regulatory Treatment - The OCC and KCC have approved the recovery of pension costs and other postretirement benefits costs through rates for Oklahoma Natural Gas and Kansas Gas Service, respectively. The costs recovered through rates are based on current funding requirements and the net periodic benefit cost for pension and postretirement costs. Differences, if any, between the expense and the amount recovered through rates are charged to earnings.

Other Employee Benefit Plans

Thrift Plan - We have a Thrift Plan covering substantially all employees. Employee contributions are discretionary. Subject to certain limits, we match employee contributions. The cost of the plan was $10.5 million, $10.4 million and $9.6 million in 2005, 2004 and 2003, respectively.

Profit Sharing Plan - We have a profit sharing plan for all nonbargaining unit employees hired after December 31, 2004. Nonbargaining unit employees who were employed prior to January 1, 2005, were given a one-time opportunity to make an irrevocable election to participate in the profit sharing plan and not accrue any additional benefits under our defined benefit pension plan after December 31, 2004. We plan to make a contribution to the profit sharing plan each quarter equal to one percent of each participant's compensation during the quarter. Additional discretionary employer contributions may be made at the end of each year. Employee contributions are not allowed under the plan. The cost of the plan was $0.6 million in 2005.

K. COMMITMENTS AND CONTINGENCIES

Leases - The initial lease term of our headquarters building, ONEOK Plaza, is for 25 years, expiring in 2009, with six five-year renewal options. At the end of the initial term or any renewal period, we can purchase the property at its fair market value. Annual rent expense for the lease will be approximately $6.8 million until 2009. Rent payments were $9.3 million in 2005, 2004 and 2003. Estimated future minimum rental payments for the lease are $9.3 million for each of the years ending December 31, 2006 through 2009.

We have the right to sublet excess office space in ONEOK Plaza. We received rental revenue of $2.8 million in 2005, 2004 and 2003. Estimated minimum future rental payments to be received under existing contracts for subleases are $3.0 million in 2006, $1.4 million in 2007, $1.3 million in 2008 and $0.8 million in 2009.

Other operating leases include a gas processing plant, office buildings, and equipment. Future minimum lease payments under non-cancelable operating leases as of December 31, 2005, are $50.7 million in 2006, $34.5 million in 2007, $32.2 million in 2008, $29.1 million in 2009 and $26.8 million in 2010. These amounts include the following minimum lease payments relating to the lease of a gas processing plant for which we have a liability as a result of uneconomic lease terms: $37.7 million in 2006, $24.2 million in 2007, $24.2 million in 2008, $24.0 million in 2009 and $24.2 million in 2010. Accordingly, the liability is amortized to rent expense in the amount of $13.0 million per year over the term of the lease. The amortization of the liability reduces rent expense; however, the cash outflow under the lease remains the same.

Environmental - We are subject to multiple environmental laws and regulations affecting many aspects of present and future operations, including air emissions, water quality, wastewater discharges, solid wastes and hazardous material and substance management. These laws and regulations generally require us to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals. Failure to comply with these laws, regulations, permits and licenses may expose us to fines, penalties and/or interruptions in our operations that could be material to the results of operations. If an accidental leak or spill of hazardous materials occurs from our lines or facilities, in the process of transporting natural gas or NGLs, or at any facility that we own, operate or otherwise use, we could be held jointly and severally liable for all resulting liabilities, including investigation and clean up costs, which could materially affect our results of operations and cash flows. In addition, emission controls required under the Federal Clean Air Act and other similar federal and state laws could require unexpected capital expenditures at our facilities. We cannot assure that existing environmental regulations will not be revised or that new regulations will not be adopted or become applicable to us. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have a material adverse effect on our business, financial condition and results of operations.

We own or retain legal responsibility for the environmental conditions at 12 former manufactured gas sites in Kansas. These sites contain potentially harmful materials that are subject to control or remediation under various environmental laws and regulations. A consent agreement with the Kansas Department of Health and Environment (KDHE) presently governs all work at these sites. The terms of the consent agreement allow us to investigate these sites and set remediation activities based upon the results of the investigations and risk analysis. We have commenced active remediation on eight sites, with regulatory closure achieved at two of these locations, and have begun assessments at the remaining four sites. The site situations are not similar, and we have no previous experience with similar remediation efforts. We have completed some analysis of the remaining four sites, but are unable to accurately estimate individual or aggregate costs that may be required to satisfy our remedial obligations.

Our preliminary review of similar cleanup efforts at former manufactured gas sites reveals that costs can range from $100,000 to $10 million per site. These estimates do not consider potential insurance recoveries, recoveries through rates or from unaffiliated parties, to which we may be entitled. At this time, we have not recorded any amounts for potential insurance recoveries or recoveries from unaffiliated parties, and we are not recovering any environmental amounts in rates. Total costs to remediate the two sites, which have achieved regulatory closure, was approximately $700,000. Total remedial costs for each of the remaining sites are expected to exceed $500,000 per site, but there is no assurance that costs to investigate and remediate the remaining sites will not be significantly higher. As more information related to the site investigations and remediation activities becomes available, and to the extent such amounts are expected to exceed our current estimates, additional expenses could be recorded. Such amounts could be material to our results of operations and cash flows depending on the remediation done and number of years over which the remediation is completed.

Our expenditures for environmental evaluation and remediation to date have not been significant in relation to the results of operations and there were no material effects upon earnings during 2005 related to compliance with environmental regulations.

Yaggy Facility - In January 2001, our Yaggy gas storage facility's operating parameters were changed as mandated by the KDHE following natural gas explosions and eruptions of natural gas geysers in or near Hutchison, Kansas. In July 2002, the KDHE issued an administrative order that assessed a civil penalty against us, based on alleged violations of several KDHE regulations. On April 5, 2004, we entered into a Consent Order with the KDHE in which we paid a civil penalty in the amount of $180,000 and reimbursed the KDHE for its costs related to the investigation of the incident in the amount of approximately $79,000. In addition, the Consent Order requires us to conduct an environmental remediation and a geoengineering study. Based on information currently available to us, we do not believe there are any material adverse effects resulting from the Consent Order.

In February 2004, a jury awarded $1.7 million in actual damages to the plaintiffs in a lawsuit involving property damage alleged to relate to the natural gas explosions and eruptions. In April 2004, the judge in this case awarded punitive damages in the amount of $5.25 million. We have filed an appeal of the jury verdict and the punitive damage award. Based on information currently available to us, we believe our legal reserves and insurance coverage is adequate and that this matter will not have a material adverse effect on us.

The two class action lawsuits filed against us in connection with the natural gas explosions and eruptions of natural gas geysers that occurred at, and in the vicinity of, our Yaggy facility in January 2001, resulted in jury verdicts in September 2004. The jury awarded the plaintiffs in the residential class $5.0 million in actual damages, and the judge ordered the payment of $2.0 million in attorney fees and $0.6 million in expenses, all of which are covered by insurance. In the other class action relating to business claims, the jury awarded no damages. The jury rejected claims for punitive damages in both cases. On April 11, 2005, the court denied the plaintiffs' motion for a new trial and denied a post-trial motion filed by defendants. We filed our notice of appeal of the residential class verdict and the attorney fee award. The cases have now been transferred to the Kansas Supreme Court for appeal. With the exception of appeals, all litigation regarding our Yaggy facility has been resolved.

Enron - We have repurchased a portion of the Enron Corp. guaranty claim that Enron Corp. and Enron North American Corp. (ENA) sought to avoid in the adversary proceeding. We are now providing the defense of the adversary proceeding for both the portion of the guaranty claim constituting the repurchased claim and also the portion of the guaranty claim previously sold. Based on information currently available to us, we do not expect the adversary proceeding to have a material adverse effect on us.

In addition to the adversary proceeding, Enron Corp. and ENA have filed a new objection to portions of the guaranty claim and to portions of the underlying claim against ENA, creating a new contested matter in the Enron Corp. and ENA bankruptcy cases which involve different legal and factual issues than those raised in the adversary proceeding. Enron Corp. and ENA allege in this matter that the guaranty claim and underlying claim against ENA are overstated. The filing of this matter may trigger additional obligations for us to repurchase some of the claims previously sold. Based on the information currently available to us, we do not expect this matter to have a material adverse effect on us.

Other - The OCC staff filed an application on February 1, 2001, to review the gas procurement practices of Oklahoma Natural Gas in acquiring its gas supply for the 2000/2001 heating season and to determine if these practices were consistent with least cost procurement practices and whether our procurement decisions resulted in fair, just and reasonable costs being borne by Oklahoma Natural Gas customers. In May 2002, we, along with the staff of the Public Utility Division and the Consumer Services Division of the OCC, the Oklahoma Attorney General, and other stipulating parties, entered into a joint settlement agreement resolving this gas cost issue and ongoing litigation related to a contract with Dynamic Energy Resources, Inc.

The settlement agreement had a $33.7 million value to Oklahoma Natural Gas customers that was realized over a three-year period. In July 2002, immediate cash savings were provided to all Oklahoma Natural Gas customers in the form of billing credits totaling approximately $9.1 million. Oklahoma Natural Gas replaced certain natural gas contracts, which reduced natural gas costs by approximately $13.8 million, due to avoided reservation fees between April 2003 and October 2005. Storage value of $2.0 million was generated on behalf of customers. As part of the final rate order issued on October 4, 2005, Oklahoma Natural Gas was authorized to net $1.8 million in under-recovered revenues authorized for recovery under the OCC's January 30, 2004 rate order against its final December 2005 billing credit obligation. In December 2005, a final billing credit of $6.9 million was made to customers.

We are a party to other litigation matters and claims, which are normal in the course of our operations. While the results of litigation and claims cannot be predicted with certainty, we believe the final outcome of such matters will not have a material adverse effect on our consolidated results of operations, financial position, or liquidity.

L. INCOME TAXES

The following table sets forth our provisions for income taxes for the periods indicated.

	Years Ended December 31,		
	2005	**2004**	**2003**
Current income taxes	*(Thousands of dollars)*		
Federal	**$186,486**	$ 40,822	$ 13,068
State	**27,589**	5,161	1,248
Total current income taxes from continuing operations	**214,075**	45,983	14,316
Deferred income taxes			
Federal	**24,780**	80,669	112,242
State	**3,666**	10,569	(454)
Total deferred income taxes from continuing operations	**28,446**	91,238	111,788
Total provision for income taxes before cumulative effect/discontinued operations	**242,521**	137,221	126,104
Total provision for income taxes for the cumulative effect of a change in accounting principle	**-**	-	(90,456)
Discontinued operations	**86,926**	12,746	27,318
Total provision for income taxes	**$329,447**	$149,967	$ 62,966

The following table is a reconciliation of our provision for income taxes for the periods indicated.

	Years Ended December 31,		
	2005	**2004**	**2003**
	(Thousands of dollars)		
Pretax income from continuing operations	**$ 645,669**	$ 361,894	$ 332,553
Federal statutory income tax rate	**35%**	35%	35%
Provision for federal income taxes	**225,984**	126,663	116,394
Amortization of distribution property investment tax credit	**(568)**	(608)	(522)
State income taxes, net of federal tax benefit	**20,316**	10,224	13,283
Other, net	**(3,211)**	942	(3,051)
Income tax expense	**$ 242,521**	$ 137,221	$ 126,104

The following table sets forth the tax effects of temporary differences that gave rise to significant portions of the deferred tax assets and liabilities for the periods indicated.

	Years Ended December 31,	
	2005	**2004**
Deferred tax assets	*(Thousands of dollars)*	
Employee benefits and other accrued liabilities	**$ 36,858**	$ 39,412
Purchased gas adjustment	**12,438**	22,884
Net operating loss carryforward	-	8,887
Other comprehensive income	**36,172**	4,784
Other	**18,412**	30,141
Total deferred tax assets	**103,880**	106,108
Valuation allowance for net operating loss carryforward expected to expire prior to utilization	-	3,426
Net deferred tax assets	**$ 103,880**	$ 102,682
Deferred tax liabilities		
Excess of tax over book depreciation and depletion	**$ 653,416**	$ 669,825
Investment in joint ventures	**11,423**	8,934
Regulatory assets	**27,990**	30,786
Other	**13,329**	11,259
Total deferred tax liabilities	**706,158**	720,804
Net deferred tax liabilities before discontinued operations	**602,278**	618,122
Discontinued operations	**(9,151)**	43,251
Net deferred tax liabilities	**$ 593,127**	$ 661,373

All federal and state net operating loss carryforwards had been utilized at December 31, 2005. At December 31, 2005, we had $4.3 million in deferred investment tax credits related to regulated operations recorded in other deferred credits, which will be amortized over the next 10 years. We had accrued income taxes of approximately $113.8 million and $0.5 million at December 31, 2005 and 2004, respectively.

M. SEGMENT INFORMATION

We have divided our operations into six reportable segments based on similarities in economic characteristics, products and services, types of customers, methods of distribution and regulatory environment. These segments are as follows: (1) our Gathering and Processing segment gathers and processes natural gas and fractionates raw NGLs; (2) our Natural Gas Liquids segment gathers, treats and fractionates raw NGLs and stores NGLs produced; (3) our Pipelines and Storage segment gathers, transports and stores natural gas for others and provides NGL gathering and distribution services; (4) our Energy Services segment markets natural gas and crude oil to wholesale and retail customers and markets electricity to wholesale customers; (5) our Distribution segment distributes natural gas to residential, commercial and industrial customers, and transports natural gas; and (6) our Other segment primarily consists of Northern Plains and the operating and leasing operations of our headquarters building and a related parking facility. Our Distribution segment is comprised of regulated public utilities and portions of our Pipelines and Storage segment are regulated.

The main customers for our Gathering and Processing segment are primarily major and independent oil and gas production companies. Our Natural Gas Liquids segment's customers are primarily gathering and processing companies and petrochemical and refining companies. Companies serviced by our Pipelines and Storage segment include LDCs, power generators, natural gas marketing companies and petrochemical companies. Our Energy Services segment buys and sells natural gas and power to LDCs, municipalities, producers, large industrials, power generators, retail aggregators and other marketing companies, as well as residential and small commercial/industrial companies. Our Distribution segment provides natural gas to residential, commercial, industrial, wholesale, public authority and transportation customers.

With the acquisition of assets from Koch on July 1, 2005, we formed a new operating segment called Natural Gas Liquids. This segment consists of our existing natural gas liquids marketing business, which was previously part of our Gathering and Processing segment, and the assets acquired from Koch excluding those natural gas liquids gathering and pipeline distribution assets regulated by the FERC, which have been transferred to our Pipelines and Storage segment. VESCO, also acquired as part of the asset acquisition, was added to our Gathering and Processing segment. Segment results for our Gathering and Processing segment for all prior periods have been restated to reflect the transfer of our existing natural gas liquids marketing business to our Natural Gas Liquids segment. Our segment formerly named Transportation and Storage has been renamed Pipelines and Storage in order to better describe the activities of the segment.

In September 2005, we completed the sale of our Production segment. Additionally, in the third quarter of 2005, we made the decision to sell our Spring Creek power plant and exit the power generation business. These components of our business are accounted for as discontinued operations in accordance with Statement 144. Our Production segment is included in our Other segment in the tables below, while our power generation business is included in our Energy Services segment.

As discussed in Note D, at the beginning of the third quarter of 2004, we completed a reorganization of our Energy Services segment and separated the management and operations of our wholesale marketing, retail marketing and trading activities. We began accounting separately for the different types of revenue earned from these activities, with certain revenues accounted for on a gross rather than a net basis.

The accounting policies of the segments are described in Note A. Intersegment gross sales are recorded on the same basis as sales to unaffiliated customers. Corporate overhead costs relating to a reportable segment have been allocated for the purpose of calculating operating income. Our equity method investments do not represent operating segments.

In 2005 and 2003, we had no single external customer from which we received 10 percent or more of our consolidated gross revenues. In 2004, we had one customer, BP PLC (BP), from which we received $745.1 million, or approximately 13 percent of consolidated revenues. Our Energy Services segment received $664.4 million of the total 2004 revenues received from BP, or approximately 11 percent, of consolidated 2004 revenues.

The following tables set forth certain selected financial information for our six operating segments for the periods indicated.

Year Ended December 31, 2005	Gathering and Processing	Natural Gas Liquids	Pipelines and Storage	Energy Services	Distribution	Other and Eliminations	Total
				(Thousands of dollars)			
Sales to unaffiliated customers	$ 263,139	$ 2,460,375	$ 70,257	$7,638,711	$2,216,207	$ 14,861	$12,663,550
Energy trading revenues, net	-	-	-	12,680	-	-	12,680
Intersegment sales	1,385,435	-	155,393	707,360	-	(2,248,188)	-
Total Revenues	$1,648,574	$ 2,460,375	$ 225,650	$8,358,751	$2,216,207	$ (2,233,327)	$12,676,230
Net margin	$ 287,266	$ 87,889	$ 171,614	$ 206,360	$ 587,700	$ (2,675)	$ 1,338,154
Operating costs	123,385	33,460	63,326	38,598	360,351	875	619,995
Depreciation, depletion and amortization	32,649	11,060	23,702	2,071	113,437	475	183,394
Gain on sale of assets	264,207	-	-	-	-	-	264,207
Operating income	$ 395,439	$ 43,369	$ 84,586	$ 165,691	$ 113,912	$ (4,025)	$ 798,972
Income (loss) from operations of discontinued component	$ -	$ -	$ -	$ (34,675)	$ -	$ 28,495	$ (6,180)
Income (loss) from equity investments	$ (6,083)	$ -	$ (1,511)	$ -	$ -	$ 10,132	$ 2,538
Total assets	$1,663,660	$ 1,617,938	$ 1,018,345	$3,030,392	$2,824,523	$ (141,392)	$10,013,466
Capital expenditures	$ 28,316	$ 12,220	$ 15,719	$ 159	$ 143,765	$ 50,314	$ 250,493

Year Ended December 31, 2004	Gathering and Processing	Natural Gas Liquids	Pipelines and Storage	Energy Services	Distribution	Other and Eliminations	Total
				(Thousands of dollars)			
Sales to unaffiliated customers	$ 255,956	$ 1,256,498	$ 65,678	$2,499,880	$1,924,502	$ (330,800)	$ 5,671,714
Energy trading revenues, net	-	-	-	113,814	-	-	113,814
Intersegment sales (a)	1,083,028	-	101,757	221,598	-	(1,406,383)	-
Total Revenues	$1,338,984	$ 1,256,498	$ 167,435	$2,835,292	$1,924,502	$ (1,737,183)	$ 5,785,528
Net margin	$ 267,030	$ 24,416	$ 126,548	$ 174,006	$ 557,316	$ (12,099)	$ 1,137,217
Operating costs	118,090	9,462	49,414	33,261	341,651	(16,366)	535,512
Depreciation, depletion and amortization	32,744	119	17,349	1,554	105,438	849	158,053
Operating income	$ 116,196	$ 14,835	$ 59,785	$ 139,191	$ 110,227	$ 3,418	$ 443,652
Income from operations of discontinued component	$ -	$ -	$ -	$ (3,183)	$ -	$ 20,688	$ 17,505
Income from equity investments	$ -		$ 1,122	$ -	$ -	$ 1,279	$ 2,401
Total assets	$1,225,077	$ 232,105	$ 801,746	$2,021,221	$2,774,279	$ 144,724	$ 7,199,152
Capital expenditures	$ 23,067	$ 9,264	$ 12,287	$ 1,806	$ 142,515	$ 75,171	$ 264,110

(a) - Intersegment sales for Energy Services were $327.3 million for the six months ended June 30, 2004. These are included in energy trading revenues, net above.

Year Ended December 31, 2003	Gathering and Processing	Natural Gas Liquids	Pipelines and Storage	Energy Services	Distribution	Other and Eliminations	Total
				(Thousands of dollars)			
Sales to unaffiliated customers	$ 287,452	$ 1,023,617	$ 68,724	$ 7,423	$1,740,060	$ (486,592)	$ 2,640,684
Energy trading revenues, net	-	-	-	229,782	-	-	229,782
Intersegment sales (a)	893,600	-	92,575	-	-	(986,175)	-
Total Revenues	$1,181,052	$ 1,023,617	$ 161,299	$ 237,205	$1,740,060	$ (1,472,767)	$ 2,870,466
Net margin	$ 198,299	$ 15,838	$ 113,662	$ 228,697	$ 526,249	$ 2,073	$ 1,084,818
Operating costs	112,822	9,281	46,186	32,226	312,814	(1,061)	512,268
Depreciation, depletion and amortization	29,273	59	16,694	1,612	95,654	1,403	144,695
Operating income	$ 56,204	$ 6,498	$ 50,782	$ 194,859	$ 117,781	$ 1,731	$ 427,855
Income from operations of discontinued component	$ -	$ -	$ -	$ 1,282	$ -	$ 8,903	$ 10,185
Cumulative effect of changes in accounting principles, net of tax	$ (1,375)	$ -	$ (645)	$ (141,982)	$ -	$ 117	$ (143,885)
Income from equity investments	$ -		$ 1,397	$ -	$ -	$ 92	$ 1,489
Total assets	$1,218,358	$ 182,001	$ 867,743	$1,610,957	$2,682,531	$ (349,704)	$ 6,211,886
Capital expenditures	$ 20,444	$ 154	$ 15,234	$ 555	$ 153,405	$ 25,356	$ 215,148

(a) - Intersegment sales for Energy Services were $487.3 million for the year ended December 31, 2003. These are included in energy trading revenues, net above.

N. QUARTERLY FINANCIAL DATA (UNAUDITED)

Total operating revenues are consistently greater during the heating season from November through March due to the large volume of natural gas sold to customers for heating. The following tables set forth the unaudited quarterly results of operations for the periods indicated.

The third quarter 2005 numbers in the following table have been restated due to a software system error we identified subsequent to the issuance of the September 30, 2005 Quarterly Report on Form 10-Q. This error impacted net margin, operating income, income from continuing operations, net income and earnings per share in the following table. No other prior periods were affected.

Year Ended December 31, 2005	**First Quarter**	**Second Quarter**	**Third Quarter Restated**	**Fourth Quarter**
	(Thousands of dollars, except per share amounts)			
Total Revenues	**$ 2,707,040**	**$ 2,080,790**	**$ 3,192,207**	**$ 4,696,193**
Net margin	**$ 370,397**	**$ 229,977**	**$ 329,319**	**$ 408,461**
Operating income	**$ 186,378**	**$ 52,183**	**$ 110,066**	**$ 450,345**
Income from continuing operations	**$ 101,778**	**$ 17,074**	**$ 44,614**	**$ 239,682**
Income (loss) from operation of discontinued components, net	**$ 5,886**	**$ 7,778**	**$ (19,582)**	**$ (262)**
Gain on sale of discontinued component, net	**$ -**	**$ -**	**$ 151,355**	**$ (1,778)**
Net Income	**$ 107,664**	**$ 24,852**	**$ 176,387**	**$ 237,642**
Earnings per share from continuing operations				
Basic	**$ 0.98**	**$ 0.17**	**$ 0.45**	**$ 2.46**
Diluted	**$ 0.92**	**$ 0.16**	**$ 0.41**	**$ 2.32**

Year Ended December 31, 2004	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**
	(Thousands of dollars, except per share amounts)			
Total Revenues	$ 982,476	$ 594,811	$ 1,664,415	$ 2,543,826
Net margin	$ 365,349	$ 205,143	$ 219,850	$ 346,875
Operating income	$ 183,627	$ 42,242	$ 48,433	$ 169,350
Income from continuing operations	$ 100,506	$ 13,128	$ 16,575	$ 94,464
Income from operation of discontinued components, net	$ 4,647	$ 4,661	$ 4,264	$ 3,933
Net Income	$ 105,153	$ 17,789	$ 20,839	$ 98,397
Earnings per share from continuing operations				
Basic	$ 1.01	$ 0.13	$ 0.16	$ 0.91
Diluted	$ 0.99	$ 0.13	$ 0.15	$ 0.86

O. SUPPLEMENTAL CASH FLOW INFORMATION

The following tables set forth supplemental information relative to our cash flow for the periods indicated.

	Years Ended December 31,		
	2005	**2004**	**2003**
Cash paid during the year		*(Thousands of dollars)*	
Interest (including amounts capitalized)	**$ 219,918**	$ 37,526	$ 115,939
Income taxes paid (received)	**$ 244,925**	$ 125,062	$ (16,302)
Non-cash transactions			
Cumulative effect of changes in accounting principles			
Rescission of EITF 98-10 (price risk management assets and liabilities)	**$ -**	$ -	$ 141,832
Adoption of Statement 143	**$ -**	$ -	$ 2,053
Issuance of restricted stock, net	**$ -**	$ -	$ 3,201
Treasury stock transferred to compensation plans	**$ 6,536**	$ -	$ 4,450

Cash paid (received) for interest includes swap terminations, treasury rate-lock terminations and ineffectiveness of $22.6 million and $(82.9) million for the years ended December 31, 2005 and 2004, respectively. There were no swap terminations, treasury rate-lock terminations or ineffectiveness for the year ended December 31, 2003.

P. STOCK BASED COMPENSATION

Deferred Compensation Plans

Employee Non-Qualified Deferred Compensation Plan - The ONEOK, Inc. Employee Non-Qualified Deferred Compensation Plan (the Prior Deferred Comp Plan) provides select employees, as approved by the Board of Directors, with the option to defer portions of their compensation and provides non-qualified deferred compensation benefits which are not available due to limitations on employer and employee contributions to qualified defined contribution plans under the federal tax laws. Under the plan, participants have the option to defer a portion of their salary and/or bonus compensation to a short-term deferral account, which pays out a minimum of five years from commencement, or a long-term deferral account, which pays out at retirement or termination of the participant's employment. Participants are immediately 100 percent vested. Short-term deferral accounts are credited with a deemed investment return based on the five-year treasury bond fund. Long-term deferral accounts are credited with a deemed investment return based on various investment options. At the distribution date, cash is distributed to participants based on the fair market value of the deemed investment of the participant account at that date.

On December 16, 2004, our Board of Directors approved certain amendments to our Prior Deferred Comp Plan, including amendments providing that the Prior Deferred Comp Plan would terminate and be frozen effective December 31, 2004, as to eligibility of any new participants and the deferral of any compensation by a participant under the Prior Deferred Comp Plan after that date. Participants in the Prior Deferred Comp Plan will be paid compensation they had deferred under the Prior Deferred Comp Plan on or before December 31, 2004, in accordance with the terms of the Prior Deferred Comp Plan.

Also, on December 16, 2004, our Board of Directors adopted the 2005 Employee Deferred Compensation Plan (the 2005 Deferred Comp Plan), which became effective January 1, 2005. The 2005 Deferred Comp Plan provides for deferral of compensation and payment of benefits in substantially the same manner as provided under the Prior Deferred Comp Plan. However, the 2005 Deferred Comp Plan contains certain different provisions intended to comply with the requirements of Section 409A of the Internal Revenue Code. Those provisions relate to participant elections to defer compensation, the timing of payments and distributions under the 2005 Deferred Comp Plan, prohibition of any foreign trust for the 2005 Deferred Comp Plan, new defined terms, and certain other conforming provisions and features.

Deferred Compensation Plan for Non-Employee Directors - The ONEOK, Inc. Deferred Compensation Plan for Non-Employee Directors provides our directors, who are not our employees, the option to defer all or a portion of their compensation for their service on our Board of Directors. Under the plan, directors may elect either a cash deferral option or a phantom stock option. Under the cash deferral option, directors may defer the receipt of all or a portion of their annual retainer and/or meeting fees, plus accrued interest. Under the phantom stock option, directors may defer all or a portion of their annual retainer and/or meeting fees and receive such fees on a deferred basis in the form of shares of common stock under our Long-Term Incentive Plan. Shares are distributed to non-employee directors at the fair market value of our common stock at the date of distribution.

Long-Term Incentive Plan

General - The ONEOK, Inc. Long-Term Incentive Plan (the LTIP) provides for the granting of stock-based compensation, including incentive stock options, non-statutory stock options, stock bonus awards, restricted stock awards, restricted stock unit awards and performance unit awards to key employees and the granting of stock awards to non-employee directors. We have reserved a total of approximately 7.8 million shares of common stock for issuance under the plan. The maximum number of shares for which options or other awards may be granted to any employee during any year is 300,000. The number of shares of stock to be paid and distributed to non-employee directors is determined by dividing the dollar amount of the director fees that are to be paid in common stock on any payment date by the fair market value of a share of common stock on that date. The LTIP is administered by the Executive Compensation Committee (the Committee). Stock options and awards could be granted until August 17, 2005.

Our Board of Directors and shareholders approved the ONEOK, Inc. Equity Compensation Plan, in February and May of 2005, respectively. This plan replaced the LTIP for new awards, but the LTIP will continue with respect to awards outstanding and the remaining shares reserved for issuance under the plan. See the Equity Compensation Plan section in this Note for additional information.

Options - Under the LTIP, stock options may be granted, which are not exercisable until a fixed future date or in installments. Prior to 2002, our stock option agreements provided for restored options to be granted. A restored option is granted in the event an optionee surrenders shares of common stock that the optionee already owns in full or partial payment of the option price of an option being exercised and/or surrenders shares of common stock to satisfy withholding tax obligations incident to the exercise of an option. A restored option is for the number of shares surrendered by the optionee and has an option price equal to the fair market value of the common stock on the date on which the exercise of an option resulted in the grant of the restored option.

Options issued to date become void upon voluntary termination of employment other than retirement. In the event of retirement or involuntary termination, the optionee may exercise the option within a period determined by the Committee and stated in the option. In the event of death, the option may be exercised by the personal representative of the optionee within a period to be determined by the Committee and stated in the option. A portion of the options issued to date can be exercised after one year from grant date and an option must be exercised no later than ten years after grant date. Restored options are exercisable at any time after six months following the grant date and expire on the expiration of the original grant.

Restricted Stock Awards - Under the LTIP, restricted stock awards may be granted to key employees with ownership of the common stock vesting over a period determined by the Committee and stated in the award. Those granted to date vest over a three-year period. Compensation expense is recognized on a straight-line basis over the period of the award. Shares awarded may not be sold during the vesting period. Dividends on restricted stock awards are reinvested in common stock.

Restricted Stock Incentive Units - Under the LTIP, restricted stock incentive units may be granted to key employees with ownership of the incentive unit vesting over a period determined by the Committee and stated in the award. Those granted in 2005 and 2004 vest over a three-year period, at which time the grantee is entitled to receive two-thirds of the grant in shares of our common stock and one-third of the grant in cash. No dividends are paid on the restricted stock incentive units. Compensation expense is recognized on a straight-line basis over the period of the award.

Performance Unit Awards - Under the LTIP, performance unit awards may be granted to key employees. The performance units vest at the expiration of a period determined by the Committee and stated in the award if certain performance criteria are met by us. Those granted to date vest at the expiration of a three-year period. Upon vesting, a holder of performance units is entitled to receive a number of shares of our common stock equal to a percentage (0 percent to 200 percent) of the performance units granted based on our total shareholder return over the vesting period, compared with the total shareholder return of a peer group of 20 other companies over the same period. Compensation expense is recognized on a straight-line basis over the period of the award with adjustments as needed based on our performance. Awards granted in 2005 and 2004 entitle the grantee to receive two-thirds of the grant in shares of our common stock and one-third of the grant in cash, while awards granted in 2003 were common stock only.

Equity Compensation Plan

General - The ONEOK, Inc. Equity Compensation Plan will replace the existing ONEOK, Inc. Long-Term Incentive Plan. The Equity Compensation Plan provides for the granting of stock-based compensation, including incentive stock options, non-statutory stock options, stock bonus awards, restricted stock awards, restricted stock unit awards, performance stock awards and performance unit awards to eligible employees and the granting of stock awards to non-employee directors. We have reserved a total of approximately 3.0 million shares of common stock for issuance under the plan. The maximum number of shares for which options or other awards may be granted to any employee during any year is 500,000. The number of shares of stock to be paid and distributed to non-employee directors is determined by dividing the dollar amount of the director fees that are to be paid in common stock on any payment date by the fair market value of a share of common stock on that date.

At December 31, 2005, there were no shares issued under this plan.

Stock Compensation Plan for Non-Employee Directors

General - The ONEOK, Inc. Stock Compensation Plan for Non-Employee Directors (the DSCP) provides for the granting of stock bonus awards, including performance unit awards, restricted stock awards, restricted stock unit awards and options. Under the DSCP, these awards may be granted by the Committee at any time on or before January 18, 2011. We have reserved a total of 700,000 shares of common stock for issuance under the DSCP. The maximum number of shares of common stock which can be issued to a participant under the DSCP during any year is 20,000.

Options - Options may be exercisable in full at the time of grant or may become exercisable in one or more installments. The plan also provides for restored options consistent with the plan for employees. Options must be exercised no later than ten years after the date of grant of the option. In the event of retirement or termination, the optionee may exercise the option within a period determined by the Committee. In the event of death, the option may be exercised by the personal representative of the optionee over a period of time determined by the Committee.

Performance Unit Awards and Restricted Stock Awards - Under the DSCP, performance unit awards and restricted stock awards may be granted at the discretion of the Committee under terms set by the Committee. These awards may be settled in cash or unrestricted shares of common stock. No performance unit awards or restricted stock awards have been made to non-employee directors under the DSCP.

Stock Option Activity

The following table sets forth the stock option activity under the LTIP and DSCP for employees and non-employee directors for the periods indicated.

	Number of Shares	Weighted Average Exercise Price
Outstanding December 31, 2002	3,063,676	$ 18.60
Granted	458,400	$ 16.79
Exercised	(413,471)	$ 16.23
Expired	(25,062)	$ 20.45
Restored	134,146	$ 21.33
Outstanding December 31, 2003	3,217,689	$ 18.75
Exercised	(921,837)	$ 17.85
Expired	(58,048)	$ 19.14
Restored	384,980	$ 23.80
Outstanding December 31, 2004	2,622,784	$ 19.79
Exercised	**(1,179,700)**	**$ 21.00**
Expired	**(31,536)**	**$ 17.14**
Restored	**540,867**	**$ 32.06**
Outstanding December 31, 2005	**1,952,415**	**$ 22.51**
Options Exercisable		
December 31, 2003	1,651,840	$ 18.94
December 31, 2004	1,541,209	$ 20.03
December 31, 2005	**1,350,387**	**$ 21.29**

At December 31, 2005, we had 942,037 outstanding options with exercise prices ranging between $13.44 to $20.16 and a weighted average remaining life of 6.00 years. Of these options, 632,350 were exercisable at December 31, 2005, with a weighted average exercise price of $17.15.

We also had 773,718 options outstanding at December 31, 2005, with exercise prices ranging between $20.17 and $30.26 and a weighted average remaining life of 4.76 years. Of these options, 717,841 were exercisable at December 31, 2005, at a weighted average exercise price of $24.93.

Additionally, we had 236,660 outstanding options at December 31, 2005, with exercise prices ranging between $30.27 and $35.49 and a weighted average remaining life of 4.41 years. Of these options, 196 were exercisable at December 31, 2005, at a weighted average exercise price of $35.49.

Restricted Stock Awards Activity

The following table sets forth activity for the restricted stock awards under the LTIP. There were no restricted stock awards under the DSCP.

	Number of Shares	Weighted Average Exercise Price
Outstanding December 31, 2002	259,854	$ 17.74
Granted	189,900	$ 16.88
Released to participants	(4,417)	$ 13.70
Forfeited	(2,686)	$ 19.15
Dividends	14,109	$ 19.48
Outstanding December 31, 2003	456,760	$ 17.47
Released to participants	(96,549)	$ 22.28
Forfeited	(2,597)	$ 17.26
Dividends	13,763	$ 23.27
Outstanding December 31, 2004	371,377	$ 16.43
Released to participants	**(179,762)**	**$ 17.38**
Forfeited	**(5,074)**	**$ 16.88**
Dividends	**7,379**	**$ 29.55**
Outstanding December 31, 2005	**193,920**	**$ 16.05**

Restricted Stock Incentive Unit Activity

The following table sets forth the activity for the restricted stock incentive units under the LTIP. There were no restricted stock units under the DSCP.

	Number of Shares	Weighted Average Exercise Price
Outstanding December 31, 2003	-	$ -
Granted	144,255	$ 20.22
Outstanding December 31, 2004	144,255	$ 20.22
Granted	**114,979**	**$ 25.19**
Released to participants	**(12,132)**	**$ 22.13**
Forfeited	**(8,166)**	**$ 22.42**
Outstanding December 31, 2005	**238,936**	**$ 22.44**

Performance Unit Activity

The following table sets forth the activity for the performance units under the LTIP. There were no performance unit awards under the DSCP.

	Number of Units	Weighted Average Exercise Price
Outstanding December 31, 2002	-	$ -
Granted	172,900	$ 15.29
Outstanding December 31, 2003	172,900	$ 15.29
Granted	191,811	$ 20.20
Outstanding December 31, 2004	364,711	$ 17.87
Granted	**266,809**	**$ 25.50**
Released to participants	**(31,133)**	**$ 20.45**
Forfeited	**(18,540)**	**$ 21.12**
Outstanding December 31, 2005	**581,847**	**$ 21.13**

Employee Stock Purchase Plan

The ONEOK, Inc. Employee Stock Purchase Plan (the ESPP) currently has 3.8 million shares reserved for issuance. Subject to certain exclusions, all full-time employees are eligible to participate. Under the terms of the plan, employees can choose to have up to ten percent of their annual base pay withheld to purchase our common stock. The Committee may allow contributions to be made by other means, provided that in no event will contributions from all means exceed ten percent of the employee's annual base pay. The purchase price of the stock is 85 percent of the lower of its grant date or exercise date market price. Approximately 63 percent, 54 percent and 58 percent of employees participated in the plan in 2005, 2004 and 2003, respectively. Under the plan, we sold 289,558 shares at $22.57 per share in 2005, 449,090 shares at $18.84 per share in 2004, and 296,125 shares at $16.23 per share in 2003.

Accounting Treatment

We adopted Statement 148 on January 1, 2003, and began expensing the fair value of all stock options granted on or after January 1, 2003. See Note A for disclosure of our pro forma net income and EPS information had we applied the provisions of Statement 123 to determine the compensation cost under these plans for stock options granted prior to January 1, 2003, for the periods presented. Effective January 1, 2006, we adopted Statement 123R. See Note A for additional information.

The fair market value of each option granted was estimated on the date of grant based on the Black-Scholes model using the following assumptions: volatility of 16.0 percent for 2005, 21.3 percent for 2004, and 30.3 percent for 2003; dividend yield of 3.8 percent for 2005, 3.9 percent for 2004, and 3.5 percent for 2003; and risk-free interest rate of 3.9 percent for 2005, 3.4 percent for 2004, and 4.0 percent for 2003.

The expected life ranged from one to ten years based upon experience to date and the make-up of the optionees. The fair value of options granted at fair market value under the Plan were $3.65, $3.53 and $4.67 for the years ended December 31, 2005, 2004 and 2003, respectively.

Q. EARNINGS PER SHARE INFORMATION

Through February 5, 2003, we computed our EPS in accordance with EITF Topic No. D-95 (Topic D-95), which was subsequently superseded by EITF Issue No. 03-6, "Participating Securities and the Two-Class Method under FASB Statement No. 128". The dilutive effect of our Series A was considered in the computation of basic EPS utilizing the "if-converted" method. Under the "if-converted" method, the dilutive effect of our Series A on EPS could not be less than the amount that would have resulted from the application of the "two-class" method of computing EPS. The "two-class" method is an earnings allocation formula that determined EPS for our common stock and our participating Series A according to dividends declared and participating rights in the undistributed earnings. Our Series A was a participating instrument with our common stock with respect to the payment of dividends. For the period from January 1, 2003 to February 5, 2003, the "two-class" method resulted in additional dilution. Accordingly, EPS for this period reflects this further dilution. As a result of our repurchase and exchange of our Series A in February 2003, we no longer applied the provisions of Topic D-95 to our EPS computations beginning in February 2003.

The following table sets forth the computation of basic and diluted EPS from continuing operations for the periods indicated.

	Year Ended December 31, 2005		
	Income	Shares	Per Share Amount
Basic EPS from continuing operations	*(Thousands, except per share amounts)*		
Income from continuing operations available for common stock	$ 403,148	100,536	**$ 4.01**
Diluted EPS from continuing operations			
Effect of other dilutive securities:			
Mandatory convertible units	-	6,366	
Options and other dilutive securities	-	1,104	
Income from continuing operations available for common stock and common stock equivalents	$ 403,148	108,006	**$ 3.73**

	Year Ended December 31, 2004		
			Per Share
	Income	Shares	Amount
Basic EPS from continuing operations	*(Thousands, except per share amounts)*		
Income from continuing operations available for common stock	$ 224,673	101,965	$ 2.21
Diluted EPS from continuing operations			
Effect of other dilutive securities:			
Mandatory convertible units	-	2,723	
Options and other dilutive securities	-	773	
Income from continuing operations available for common stock and common stock equivalents	$ 224,673	105,461	$ 2.13

	Year Ended December 31, 2003		
			Per Share
	Income	Shares	Amount
Basic EPS from continuing operations	*(Thousands, except per share amounts)*		
Income from continuing operations available for common stock under D-95	$ 26,174	62,055	
Series A Convertible Preferred Stock dividends	12,139	39,893	
Income from continuing operations available for common stock and assumed conversion of Series A Convertible Preferred Stock	38,313	101,948	$ 0.37
Further dilution from applying the "two-class" method			$ (0.08)
Basic EPS from continuing operations under D-95			$ 0.29
Income from continuing operations available for common stock not under D-95	156,064	78,585	$ 1.99
Basic EPS from continuing operations			$ 2.28
Diluted EPS from continuing operations			
Income from continuing operations available for Series D Convertible Preferred Stock dividends	194,377	80,569	
Effect of other dilutive securities:			
Options and other dilutive securities	-	911	
Series D Convertible Preferred Stock dividends	12,072	15,519	
Income from continuing operations	$ 206,449	96,999	$ 2.13
Further dilution from applying the "two-class" method			$ (0.08)
Diluted EPS from continuing operations			$ 2.05

There were 28,107, 17,734 and 151,448 option shares excluded from the calculation of diluted EPS for the years ended December 31, 2005, 2004 and 2003, respectively, since their inclusion would be antidilutive.

The repurchase and exchange of our Series A from Westar in February 2003 was recorded at fair value. In accordance with Topic No. D-42, “The Effect of the Calculation of Earnings Per Share for the Redemption or Induced Conversion of Preferred Stock,” the premium, or the excess of the fair value of the consideration transferred to Westar over the carrying value of the Series A, was considered a preferred dividend. The premium recorded on the repurchase and exchange of the Series A was approximately $44.2 million and $53.4 million, respectively, for a total premium of $97.6 million. As a result of our adoption of Topic D-95, we recognized additional dilution of approximately $94.5 million through the application of the “two-class” method of computing EPS. This additional dilution offsets the total premium recorded, resulting in a net premium of $3.1 million, which is reflected as a dividend on the Series A in the EPS calculation above for the year ended December 31, 2003.

R. RELATIONSHIPS WITH NORTHERN BORDER PARTNERS

In November 2004, we acquired Northern Plains, which owns 82.5 percent of the general partner interest and 500,000 limited partnership units, together representing a 2.73 percent ownership interest, in Northern Border Partners, from CCE Holdings, LLC for $175 million.

With our acquisition of Northern Plains in November 2004, we entered into a transition services agreement with Northern Border Partners. We provide certain administrative, operating and management services to Northern Border Partners and are reimbursed for these direct and indirect costs and expenses. In 2005, the aggregate amount we charged Northern Border Partners for services was approximately $52.6 million.

Our Energy Services segment became affiliated with Northern Border Pipeline in November 2004, in connection with our purchase of Northern Plains, and holds contracts for firm transportation on Northern Border Pipeline that represents approximately three percent of its design capacity. In 2005, our Energy Services segment paid Northern Border Pipeline $7.7 million related to these transportation contacts.

In 2005, Northern Border Partners paid us total cash distributions of $9.3 million, which included $5.7 million related to our incentive distribution rights.

S. SUBSEQUENT EVENT

On February 14, 2006, we signed agreements to sell certain assets to Northern Border Partners for approximately $3 billion in cash and limited partner units and increase our general partner interest in Northern Border Partners to 100 percent. We will purchase, through Northern Plains, from an affiliate of TransCanada Corporation (TransCanada) 17.5 percent of the general partner interest in Northern Border Partners for $40 million, less $10 million for expenses associated with the transfer of operating responsibility of Northern Border Pipeline Company to TransCanada for a net payment of $30 million. After the transactions are completed, we will own approximately 37.0 million limited partner units and 100 percent of the Northern Border Partners' general partner interest, increasing our total interest in Northern Border Partners to 45.7 percent.

With the purchase of 17.5 percent of the general partner interest in Northern Border Partners, we will also transfer our Gathering and Processing segment, Natural Gas Liquids segment, and Pipelines and Storage segment to Northern Border Partners in transactions valued at approximately $3 billion. We will receive approximately $1.35 billion in cash and approximately 36.5 million limited partner units from Northern Border Partners. The limited partner units and related general partner interest contribution were valued at approximately $1.65 billion at the time of the signing of the transaction. This sale, subject to adjustment, includes the natural gas liquids assets we purchased from Koch in July 2005 for $1.35 billion. We will not recognize a gain on the sale as the transfer of assets will be accounted for at the assets' historical cost. We plan to use the cash proceeds to reduce short-term debt, acquire other assets or repurchase our common stock.

The limited partner units we will receive from Northern Border Partners will be a newly created Class B unit with the same distribution rights as the outstanding common units, but will have limited voting rights and will be subordinated to the common units with respect to payment of minimum quarterly distributions. Distributions on the Class B units will be prorated from the date of issuance. Northern Border Partners is required to hold a special election for holders of common units within 12 months of issuing the Class B units to approve the conversion of the Class B units into common units and to approve certain amendments to the partnership agreement. The proposed amendments grant voting rights for common units held by the general partner if a vote is held to remove the general partner and require fair market value compensation for the general partner interest if the general partner is removed. If the common unit holders do not approve both the conversion and amendments within 12 months of the issuance of the Class B units, then the amount payable on such Class B units would increase to 115 percent of the distributions paid on the common units and the Class B distribution rights would continue to be subordinated in the manner described above unless and until the conversion described above has been approved. If the common unit holders vote to remove us or our affiliates as the general partner of Northern Border Partners at any time prior to the approval of the conversion and amendment described above, the amount payable on such Class B units would increase to 125 percent of the distributions payable with respect to the common units and the Class B unit distribution rights would continue to be subordinated in the manner described above unless and until the conversion described above has been approved.

These transactions are subject to regulatory approvals and other conditions, including antitrust clearance from the Federal Trade Commission under the Hart-Scott-Rodino Act. We expect these transactions will be completed by April 1, 2006.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Not applicable.

ITEM 9A. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

We have established disclosure controls and procedures to ensure that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Securities and Exchange Act of 1934, as amended (the "Act") is recorded, processed, summarized and reported, within the time periods specified in the U.S. Securities and Exchange Commission's rules and forms. Under the supervision and with the participation of senior management, including our Chairman and Chief Executive Officer ("Principal Executive Officer") and our Chief Financial Officer ("Principal Financial Officer"), we evaluated our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Act. Based on this evaluation, our Principal Executive Officer and our Principal Financial Officer concluded that due to the material weakness described below under the heading "Management's Report on Internal Control Over Financial Reporting" (Item 9A(b)), our disclosure controls and procedures were not effective as of the end of the period covered by this annual report.

(b) Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including our Principal Executive Officer and Principal Financial Officer, we evaluated the effectiveness of our internal control over financial reporting based on the framework in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

A material weakness is a control deficiency, or combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected. In February 2006, we identified a software system error impacting our accounting for hedging instruments that led management to conclude that the following material weakness existed as of December 31, 2005.

> Our third party software system associated with accounting for derivative hedging instruments was inadequately designed to appropriately account for certain hedges of forecasted transactions and thus did not facilitate the recognition of hedging ineffectiveness in accordance with generally accepted accounting principles. The software system incorrectly reversed previously recognized hedging ineffectiveness when additional derivative instruments (basis swaps) were incorporated into our hedging strategy related to the forecasted transactions. As a result, misstatements were identified in the Company's cost of sales and fuel account and accumulated other comprehensive income (loss) and were corrected prior to the issuance of the 2005 consolidated financial statements.

Management has determined that the aforementioned deficiency constitutes a material weakness in our internal control over financial reporting as of December 31, 2005, based on our evaluation under the framework in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Accordingly, management concluded that our internal control over financial reporting was not effective as of December 31, 2005.

We acquired Koch Industries Inc.'s natural gas liquids business in July 2005 (herein after referred to as "the Natural Gas Liquids segment"). Management excluded from our assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2005, internal control over financial reporting associated with our Natural Gas Liquids segment, which represents approximately 19 percent of our total revenue in 2005 and approximately 16 percent of our total assets included in our consolidated financial statements as of December 31, 2005.

Management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2005, has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report which is included herein (Item 8).

(c) Changes in Internal Controls Over Financial Reporting

We have not made any changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) under the Act) during the fiscal year ended December 31, 2005, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting, except for those controls described below.

In July 2005, we completed the acquisition of the Natural Gas Liquids segment as more fully described in Note B in the Notes to our Consolidated Financial Statements included in Part II of this report. As part of our ongoing integration activities, we are in the process of developing and incorporating controls and procedures related to these assets into our internal controls over financial reporting. Until such controls are more fully developed, we have implemented and are relying on compensating controls and have performed extensive reviews of our reported results. As with any acquisition, there are inherent risks in the timing, development and implementation of internal controls that could negatively impact us; however, we do not believe they will have a material impact on our financial statements.

Subsequent to December 31, 2005, we discovered the material weakness described above. We have developed additional controls to manually review and revalue the hedging ineffectiveness calculated by the affected software. We are also performing additional analytical reviews and reconciliations of reports generated by the affected software. Management believes that the additional controls will remediate the deficiency; however, such determination will not occur until the additional controls have been in place for a period of time sufficient to demonstrate that the controls are operating effectively. Additionally, we are working with the third party software vendor to correct the affected software. Until we are satisfied that the software is operating correctly, we will continue to rely on the additional manual controls described above.

ITEM 9B. OTHER INFORMATION

Not applicable.

PART III.

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Directors of the Registrant

Information concerning our directors is set forth in our 2006 definitive Proxy Statement and is incorporated herein by this reference.

Executive Officers of the Registrant

Information concerning our executive officers is included in Part I, Item 1. Business, of this Annual Report on Form 10-K.

Compliance with Section 16(a) of the Exchange Act

Information on compliance with Section 16(a) of the Exchange Act is set forth in our 2006 definitive Proxy Statement and is incorporated herein by this reference.

Code of Ethics

Information concerning the code of ethics, or code of business conduct, is set forth in our 2006 definitive Proxy Statement and is incorporated herein by this reference.

Nominating Committee Procedures

Information concerning the nominating committee procedures is set forth in our 2006 definitive Proxy Statement and is incorporated herein by this reference.

ITEM 11. EXECUTIVE COMPENSATION

Information on executive compensation is set forth in our 2006 definitive Proxy Statement and is incorporated herein by this reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Security Ownership of Certain Beneficial Owners

Information concerning the ownership of certain beneficial owners is set forth in our 2006 definitive Proxy Statement and is incorporated herein by this reference.

Security of Ownership of Management

Information on security ownership of directors and officers is set forth in our 2006 definitive Proxy Statement and is incorporated herein by this reference.

Equity Compensation Plan Information

Information concerning our equity compensation plans is included in Part II, Item 5. Market for Registrant’s Common Equity and Related Shareholder Matters of this Annual Report on Form 10-K.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Information on certain relationships and related transactions is set forth in our 2006 definitive Proxy Statement and is incorporated herein by this reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information concerning the principal accountant’s fees and services is set forth in our 2006 definitive Proxy Statement and is incorporated herein by this reference.

PART IV.

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

Documents Filed as Part of this Report

(1) Exhibits

3 Certificate of Incorporation of WAI, Inc. (now ONEOK, Inc.) filed May 16, 1997 (incorporated by reference from Exhibit 3.1 to Amendment No. 3 to Registration Statement on Form S-4 filed August 6, 1997, Commission File No. 333-27467).

3.1 Certificate of Merger of ONEOK, Inc. (formerly WAI, Inc.) filed November 26, 1997 (incorporated by reference from Exhibit (1)(b) to Form 10-Q for the quarter ended May 31, 1998, filed June 26, 1998).

3.2 Amended Certificate of Incorporation of ONEOK, Inc. filed January 16, 1998 (incorporated by reference from Exhibit (1)(a) to Form 10-Q for the quarter ended May 31, 1998, filed June 26, 1998).

3.3 Amendment to Certificate of Incorporation of ONEOK, Inc. filed May 23, 2001 (incorporated by reference from Exhibit 4.6 to Registration Statement on Form S-3 filed July 19, 2001, as amended, Commission File No. 333-65392).

3.4 Bylaws of ONEOK, Inc. (incorporated by reference from Exhibit 3 to Form 10-Q for the quarter ended March 31, 2004, filed April 30, 2004).

4 Certificate of Designation for Convertible Preferred Stock of WAI, Inc. (now ONEOK, Inc.) filed November 26, 1997 (incorporated by reference from Exhibit 3.3 to Amendment No 3. to Registration Statement on Form S-4 filed August 6, 1997, Commission File No. 333-27467).

4.1 Certificate of Designation for Series C Participating Preferred Stock of ONEOK, Inc. filed November 26, 1997 (incorporated by reference from Exhibit No. 1 to Registration Statement on Form 8-A filed November 28, 1997).

4.2 Form of Common Stock Certificate (incorporated by reference from Exhibit 1 to Registration Statement on Form 8-A filed November 21, 1997).

4.3 Indenture, dated September 24, 1998, between ONEOK, Inc. and Chase Bank of Texas (incorporated by reference from Exhibit 4.1 to Registration Statement on Form S-3 filed August 26, 1998, Commission File No. 333-62279).

4.4 Indenture dated December 28, 2001, between ONEOK, Inc. and SunTrust Bank (incorporated by reference from Exhibit 4.1 to Amendment No. 1 to Registration Statement on Form S-3 filed December 28, 2001, Commission File No. 333-65392).

4.5 First Supplemental Indenture dated September 24, 1998, between ONEOK, Inc. and Chase Bank of Texas (incorporated by reference from Exhibit 5(a) to Form 8-K filed September 24, 1998).

4.6 Second Supplemental Indenture dated September 25, 1998, between ONEOK, Inc. and Chase Bank of Texas (incorporated by reference from Exhibit 5(b) to Form 8-K filed September 24, 1998).

4.7 Third Supplemental Indenture dated February 8, 1999, between ONEOK, Inc. and Chase Bank of Texas (incorporated by reference from Exhibit 4 to Form 8-K filed February 8, 1999).

4.8 Fourth Supplemental Indenture dated February 17, 1999, between ONEOK, Inc. and Chase Bank of Texas (incorporated by reference from Exhibit 4.5 to Registration Statement on Form S-3 filed April 15, 1999, Commission File No. 333-76375).

4.9 Fifth Supplemental Indenture dated August 17, 1999, between ONEOK, Inc. and Chase Bank of Texas (incorporated by reference from Exhibit 4 to Form 8-K filed August 17, 1999).

4.10 Sixth Supplemental Indenture dated March 1, 2000, between ONEOK, Inc. and Chase Bank of Texas (incorporated by reference from Exhibit 4.11 to the Registration Statement on Form S-4 filed March 13, 2000, Commission File No. 333-32254).

4.11 Seventh Supplemental Indenture dated April 24, 2000, between ONEOK, Inc. and Chase Bank of Texas (incorporated by reference from Exhibit 4 to Form 8-K filed April 26, 2000).

4.12 Eighth Supplemental Indenture dated April 6, 2001, between ONEOK, Inc. and The Chase Manhattan Bank (incorporated by reference from Exhibit 4.9 to Registration Statement on Form S-3 filed July 19, 2001, Commission File No. 333-65392).

4.13 First Supplemental Indenture, dated as of January 28, 2003, between ONEOK, Inc. and SunTrust Bank (incorporated by reference from Exhibit 4.22 to Registration Statement on Form 8-A/A filed January 31, 2003).

4.14 Second Supplemental Indenture, dated June 17, 2005, between ONEOK, Inc. and SunTrust Bank (incorporated by reference from Exhibit 4.1 to Form 8-K filed June 17, 2005).

4.15 Third Supplemental Indenture, dated June 17, 2005, between ONEOK, Inc. and SunTrust Bank (incorporated by reference from Exhibit 4.3 to Form 8-K filed June 17, 2005).

4.16 Form of Senior Note Due 2008 (included in Exhibit 4.13).

4.17 Form of 5.20% Notes Due 2015 (included in Exhibit 4.14).

4.18 Form of 6.00% Notes due 2035 (included in Exhibit 4.15).

4.19 Purchase Contract Agreement, dated January 28, 2003, between ONEOK, Inc. and SunTrust Bank, as Purchase Contract Agent (incorporated by reference from Exhibit 4.3 to Registration Statement on Form 8-A/A filed January 31, 2003).

4.20 Form of Corporate Unit (included in Exhibit 4.19).

4.21 Pledge Agreement, dated January 28, 2003, among ONEOK, Inc., SunTrust Bank, as Collateral Agent, Custodial Agent and Securities Intermediary, and SunTrust Bank, as Purchase Contract Agent (incorporated by reference from Exhibit 4.4 to Registration Statement on Form 8-A/A filed January 31, 2003).

4.22 Remarketing Agreement, dated January 28, 2003, among ONEOK, Inc., UBS Warburg LLC, Banc of America LLC and J.P. Morgan Securities Inc. and SunTrust Bank, as Purchase Contract Agent (incorporated by reference from Exhibit 4.5 to Registration Statement on Form 8-A/A filed January 31, 2003).

4.23 Remarketing Agreement Supplement (incorporated by reference from Exhibit 1.1 to Form 8-K filed November 16, 2005).

4.24 Amended and Restated Rights Agreement dated as of February 5, 2003, between ONEOK, Inc. and UMB Bank, N.A., as Rights Agent (incorporated by reference from Exhibit 1 to Registration Statement on Form 8-A/A (Amendment No. 1) filed February 6, 2003).

10 ONEOK, Inc. Long-Term Incentive Plan (incorporated by reference from Exhibit 10(a) to Form 10-K for the fiscal year ended December 31, 2001, filed March 14, 2002).

10.1 ONEOK, Inc. Stock Compensation Plan for Non-Employee Directors (incorporated by reference from Exhibit 99 to Form S-8 filed January 25, 2001).

10.2 ONEOK, Inc. Supplemental Executive Retirement Plan terminated and frozen December 31, 2004 (incorporated by reference from Exhibit 10.1 to Form 8-K filed on December 20, 2004).

10.3 ONEOK, Inc. 2005 Supplemental Executive Retirement Plan dated January 1, 2005 (incorporated by reference from Exhibit 10.2 to Form 8-K filed on December 20, 2004).

10.4 Termination Agreements between ONEOK, Inc. and ONEOK, Inc. executives, as amended, dated January 1, 2003 (incorporated by reference from Exhibit 10.3 to Form 10-K for the fiscal year ended December 31, 2002, filed March 10, 2003).

10.5 Indemnification Agreement between ONEOK, Inc. and ONEOK, Inc. officers and directors, as amended, dated January 1, 2003 (incorporated by reference from Exhibit 10.4 to Form 10-K for the fiscal year ended December 31, 2002, filed March 10, 2003).

10.6 ONEOK, Inc. Annual Officer Incentive Plan (incorporated by reference from Exhibit 10(f) to Form 10-K for the fiscal year ended December 31, 2001, filed March 14, 2002).

10.7 ONEOK, Inc. Employee Nonqualified Deferred Compensation Plan, as amended December 16, 2004 (incorporated by reference from Exhibit 10.3 to Form 8-K filed December 20, 2004).

10.8 ONEOK, Inc. 2005 Nonqualified Deferred Compensation Plan dated January 1, 2005 (incorporated by reference from Exhibit 10.4 to Form 8-K filed December 20, 2004).

10.9 ONEOK, Inc. Deferred Compensation Plan for Non-Employee Directors, as amended and restated November 19, 1998 (incorporated by reference from Exhibit 10.7 to Form 10-K for the fiscal year ended December 31, 2002, filed March 10, 2003).

10.10 Ground Lease between ONEOK Leasing Company and Southwestern Associates dated May 15, 1983 (incorporated by reference from Form 10-K dated August 31, 1983).

10.11 First Amendment to Ground Lease between ONEOK Leasing Company and Southwestern Associates dated October 1, 1984 (incorporated by reference from Form 10-K dated August 31, 1984).

10.12 Sublease between RMZ Corp. and ONEOK Leasing Company dated May 15, 1983 (incorporated by reference from Form 10-K dated August 31, 1984).

10.13 First Amendment to Sublease between RMZ Corp. and ONEOK Leasing Company dated October 1, 1984 (incorporated by reference from Form 10-K dated August 31, 1984).

10.14 ONEOK Leasing Company Lease Agreement with Oklahoma Natural Gas Company dated August 31, 1984 (incorporated by reference from Form 10-K dated August 31, 1985).

10.15 Second Amendment to Credit Agreement among ONEOK, Inc., as the Borrower, Bank of America, N.A., as Administrative Agent for the Lenders and as a Lender and L/C Issuer, and the Lenders, effective as of July 25, 2005 (incorporated by reference from Exhibit 10.5 to the Form 10-Q for the quarter ended June 30, 2005, filed August 3, 2005).

10.16 Third Amendment to Credit Agreement among ONEOK, Inc., Bank of America, N.A., as Administration Agent and as a lender and L/C issuer, and the Lenders, dated September 13, 2005 (incorporated by reference from Exhibit 10.2 to the Form 10-Q for the quarter ended September 30, 2005, filed November 4, 2005).

10.17 Fourth Amendment to Credit Agreement among ONEOK, Inc., Bank of America, N.A., dated September 1, 2005 (incorporated by reference from Exhibit 10.3 to the Form 10-Q for the quarter ended September 30, 2005, filed November 4, 2005).

10.18 $1,000,000,000 Credit Agreement dated as of June 27, 2005, among ONEOK, Inc., as the Borrower, Citibank, N.A, as the Administrative Agent and as a Lender, and the Lenders party thereto (incorporated by reference from Exhibit 10.1 to Form 8-K filed June 29, 2005).

10.19 First Amendment to Credit Agreement among ONEOK, Inc., Citibank, N.A., as Administrative Agent and as a Lender, and the Lenders party thereto, dated September 1, 2005 (incorporated by reference from Exhibit 10.1 to the Form 10-Q for the quarter ended September 30, 2005, filed November 4, 2005).

10.20 $10,000,000 Credit Agreement dated as of April 20, 2004 between ONEOK, Inc., as the Borrower, and KBC Bank, N.V (incorporated by reference from Exhibit 10.23 to the Form 10-K for the year ended December 31, 2004, filed March 8, 2005).

10.21 Purchase Agreement between CCE Holdings, LLC and ONEOK, Inc. dated as of September 16, 2004 (incorporated by reference from Exhibit 10.25 to the Form 10-K for the year ended December 13, 2004, filed March 8, 2005).

10.22 Purchase Agreement between Koch Hydrocarbon Management Company, LLC and ONEOK, Inc. dated May 9, 2005 (incorporated by reference from Exhibit 10.1 to the Form 10-Q for the quarter ended June 30, 2005, filed August 3, 2005).

10.23 Asset Purchase Agreement between Koch Pipeline Company, L.P. and ONEOK, Inc. dated May 9, 2005 (incorporated by reference from Exhibit 10.2 to the Form 10-Q for the quarter ended June 30, 2005, filed August 3, 2005).

10.24 Limited Liability Company Membership Interest Purchase Agreement between Koch Holdings Enterprises, LLC and ONEOK, Inc. dated May 9, 2005 (incorporated by reference from Exhibit 10.3 to the Form 10-Q for the quarter ended June 30, 2005, filed August 3, 2005).

10.25 Limited Liability Company Membership Interest Purchase Agreement between Koch Hydrocarbon Management Company, LLC and ONEOK, Inc. dated May 9, 2005 (incorporated by reference from Exhibit 10.4 to the Form 10-Q for the quarter ended June 30, 2005, filed August 3, 2005).

10.26 Limited Liability Company Membership Interest Purchase Agreement between TXOK Acquisition, Inc. and ONEOK Energy Resources Company dated September 19, 2005 (incorporated by reference from Exhibit 10.4 to the Form 10-Q for the quarter ended September 30, 2005, filed November 4, 2005).

10.27 Amendment No. 1 to Limited Liability Company Membership Interest Purchase Agreement between TXOK Acquisition, Inc., and ONEOK Energy Resources Company dated September 27, 2005 (incorporated by reference from Exhibit 10.6 to the Form 10-Q for the quarter ended September 30, 2005, filed November 4, 2005).

10.28 Stock Purchase Agreement between TXOK Acquisition, Inc. and ONEOK, Inc., dated September 19, 2005 (incorporated by reference from Exhibit 10.5 to the Form 10-Q for the quarter ended September 30, 2005, filed November 4, 2005).

10.29 Amendment No. 1 to Stock Purchase Agreement between TXOK Acquisition, Inc., and ONEOK, Inc., dated September 27, 2005 (incorporated by reference from Exhibit 10.7 to the Form 10-Q for the quarter ended September 30, 2005, filed November 4, 2005).

10.30 Purchase and Sale Agreement by and between TransCan Northwest Border Ltd. and Northern Plains Natural Gas Company, LLC, dated February 14, 2006.

10.31 Purchase and Sale Agreement by and between ONEOK, Inc. and Northern Border Partners, L.P., dated February 14, 2006.

10.32 Contribution Agreement by and among ONEOK. Inc., Northern Border Partners, L.P. and Northern Border Intermediate Limited Partnership, dated February 14, 2006.

10.33 Form of Services Agreement to be entered into among ONEOK, Inc. and its affiliates and Northern Border Partners, L.P. and Northern Border Intermediate Limited Partnership.

10.34 Form of Amendment No. 1 Amended and Restated Agreement of Limited Partnership of Northern Border Partners, L.P., to be entered into among Northern Plains Natural Gas Company, LLC, Pan Border Gas Company, LLC and Northwest Border Pipeline Company.

10.35 ONEOK, Inc. Profit Sharing Plan dated January 1, 2005 (incorporated by reference from Exhibit 99 to Registration Statement on Form S-8 filed December 30, 2004).

10.36 ONEOK, Inc. Employee Stock Purchase Plan, as amended and restated February 17, 2005 (incorporated by reference from Exhibit 10.2 to the Form 8-K filed February 23, 2005).

10.37 Form of Non-Statutory Stock Option Agreement (incorporated by reference from Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2004, filed November 3, 2004).

10.38 Form of Restricted Stock Award Agreement (incorporated by reference from Exhibit 10.2 to Form 10-Q for the quarter ended September 30, 2004, filed November 3, 2004).

10.39 Form of Performance Shares Award Agreement (incorporated by reference from Exhibit 10.3 to Form 10-Q for the quarter ended September 30, 2004, filed November 3, 2004).

10.40 Form of Restricted Stock Incentive Award Agreement (incorporated by reference from Exhibit 10.4 to Form 10-Q for the quarter ended September 30, 2004, filed November 3, 2004).

10.41 Form of Performance Shares Award Agreement (incorporated by reference from Exhibit 10.5 to Form 10-Q for the quarter ended September 30, 2004, filed November 3, 2004).

10.42 ONEOK, Inc. Equity Compensation Plan dated effective February 17, 2005 (incorporated by reference from Exhibit 10.1 to Form 8-K filed February 23, 2005).

10.43 Form of Restricted Unit Award Agreement.

10.44 Form of Performance Unit Award Agreement.

12 Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividend Requirements for the years ended December 31, 2005, 2004, 2003, 2002 and 2001.

12.1 Computation of Ratio of Earnings to Fixed Charges for the years ended December 31, 2005, 2004, 2003, 2002 and 2001.

21 Required information concerning the registrant's subsidiaries.

23 Consent of Independent Registered Public Accounting Firm.

31.1 Certification of David L. Kyle pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 Certification of Jim Kneale pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 Certification of David L. Kyle pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished only pursuant to Rule 13a-14(b)).

32.2 Certification of Jim Kneale pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished only pursuant to Rule 13a-14(b)).

(2) Financial Statements

(3) Financial Statement Schedules

All schedules have been omitted because of the absence of conditions under which they are required.

Signatures

Pursuant to the requirements of Section 13 or 15(d) 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.

ONEOK, Inc.
Registrant

Date: March 8, 2006

By: /s/Jim Kneale
Jim Kneale
Executive Vice President -
Finance and Administration
and Chief Financial Officer
(Principal Financial Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on this 8th day of March 2006.

/s/ David L. Kyle
David L. Kyle
Chairman of the Board of
Directors, President, and
Chief Executive Officer

/s/ Curtis L. Dinan
Curtis L. Dinan
Senior Vice President and
Chief Accounting Officer

/s/ William M. Bell
William M. Bell
Director

/s/ Douglas A. Newsom
Douglas A. Newsom
Director

/s/ James C. Day
James C. Day
Director

/s/ Gary D. Parker
Gary D. Parker
Director

/s/ William L. Ford
William L. Ford
Director

/s/ Eduardo A. Rodriguez
Eduardo A. Rodriguez
Director

/s/ Bert H. Mackie
Bert H. Mackie
Director

/s/ Mollie B. Williford
Mollie B. Williford
Director

/s/ Pattye L. Moore
Pattye L. Moore
Director

GLOSSARY

Hedge, Hedging: The use of derivative commodity and interest rate instruments to reduce financial exposure to commodity price and interest rate volatility.

Master Limited Partnership (MLP): A limited partnership business that is publicly traded on an exchange such as the New York Stock Exchange. MLPs have one or more general partners who manage the business and assume its legal debts and obligations.

Natural Gas Liquids (NGLs): Liquid hydrocarbons that are extracted and separated from the natural gas stream. NGL products include ethane, propane, isobutane, butane and natural gasoline.

NYMEX: The New York Mercantile Exchange, the largest physical commodities trading forum in the world.

Option: A contractual agreement where the seller grants a right to the buyer for a fee to buy or sell a commodity, security or asset at a given price on or before a specific date.

Partnership Units: The ownership interests owned by partners – the investors – in a partnership similar to owning shares of stock in a corporation.

Risk: Exposure to uncertainty.

Units of Measure:

Mcf = Thousand cubic feet	Bbls = Barrels (42 U.S. gallons)
MMcf = Million cubic feet	MBbls = Thousand barrels
Bcf = Billion cubic feet	MGal= Thousand gallons
MMMBtu/d = Billion Btus per day	

When "e" follows any of the above, the oil and natural gas liquids components have been converted to their equivalents in cubic feet at a rate of 6 Mcf per barrel.

CORPORATE INFORMATION

- ONEOK is a diversified energy company
- Founded in 1906 as an intrastate pipeline business
- Markets and trades energy commodities
- Involved in all aspects of the natural gas industry
- Listed on the New York Stock Exchange under the symbol OKE

Annual Meeting
The annual meeting of shareholders will be held Thursday, May 18, 2006, at 10 a.m. Central Time, at ONEOK Plaza, 100 West Fifth Street, Tulsa, Oklahoma.

Auditors
KPMG LLP
100 West Fifth Street, Suite 310
Tulsa, OK 74103-9919

Direct Stock Purchase and Dividend Reinvestment Plan
The company's Direct Stock and Dividend Reinvestment Plan provides investors the opportunity to purchase shares of common stock without payment of any brokerage fees or service charges.

Transfer Agent, Registrar and Dividend Disbursing Agent
UMB Bank, N.A.
Securities Transfer Division
P.O. Box 410064
Kansas City, MO 64141-0064
Phone Toll Free: (866) 235-0232
Hours: Weekdays, 8 a.m. – 4:30 p.m., CST
E-mail: stock.transfer@umb.com
Web Site: www.umb.com/business/shareholder/

Credit Rating

Standard & Poor's	BBB
Moody's Investors Service	Baa2

Stock Trading
The common stock is listed on the New York Stock Exchange.
The ticker symbol for ONEOK common stock is OKE.
The corporate name ONEOK is used in newspaper stock listings.

Master Limited Partnership Units
Common units for Northern Border Partners, L.P. trade on the New York Stock Exchange under the symbol NBP.

Investor Relations
Contact Dan Harrison, vice president – communications and investor relations, by phone at (918) 588-7950 or by e-mail at dan.harrison@oneok.com.

Corporate Web Site
ONEOK business and financial information is available at www.oneok.com.

Sarbanes-Oxley Act Certification
David L. Kyle, chief executive officer, and James C. Kneale, chief financial officer, have each filed with the Securities and Exchange Commission the written certifications required by Section 302 of the Sarbanes-Oxley Act of 2002 and the rules of the Securities and Exchange Commission. These certifications are included as exhibits 31.1 and 31.2 of the ONEOK, Inc. Annual Report on Form 10-K for the year ended December 31, 2005.

New York Stock Exchange Certification
As required by the listing standards of the New York Stock Exchange, on June 1, 2005, David L. Kyle, chief executive officer, submitted to the New York Stock Exchange the Annual CEO Certification that he was not aware of any violation by ONEOK, Inc. of the New York Stock Exchange listing standards. We anticipate filing our 2006 Annual CEO Certification with the New York Stock Exchange on or about May 29, 2006.

Forward-looking Statements. Certain matters discussed in this report, excluding historical information, include forward-looking statements. Although ONEOK, Inc. believes such forward-looking statements are based on reasonable assumptions, no assurance can be given that each statement about the future will be realized. Such statements are made in reliance on the "safe harbor" protections provided under the Private Securities Litigation Reform Act of 1995. For more detail, see pages 51-52 of the Form 10-K.

ONEOK

100 West Fifth Street   Post Office Box 871 Tulsa, OK 74102-0871   www.oneok.com