ENERGEN CORP
Form 10-K
February 25, 2008

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 YEAR ENDED DECEMBER 31, 2007**

¨ **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	Registrant	State of Incorporation	IRS Employer Identification Number
1-7810	Energen Corporation	Alabama	63-0757759
2-38960	Alabama Gas Corporation	Alabama	63-0022000

605 Richard Arrington Jr. Boulevard North, Birmingham, Alabama 35203-2707

Telephone Number 205/326-2700

http://www.energen.com

Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	Exchange on Which Registered
Energen Corporation Common Stock, $0.01 par value	**New York Stock Exchange**
Energen Corporation Preferred Stock Purchase Rights	**New York Stock Exchange**

Securities Registered Pursuant to Section 12(g) of the Act: NONE

Indicate by check mark if the registrants are a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES x NO ¨

Indicate by check mark if the registrants are not required to file reports pursuant to Section 13 or Section 15(d) of the Act. YES ¨ NO x

Indicate by a check mark whether registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities and Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports) and (2) have been subject to such filing requirements for the past 90 days. YES x NO ¨

Indicate by a check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation 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 check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Energen Corporation	Large accelerated filer x	Accelerated filer ¨	Non-accelerated filer ¨	Smaller reporting company ¨
Alabama Gas Corporation	Large accelerated filer ¨	Accelerated filer ¨	Non-accelerated filer x	Smaller reporting company ¨

Indicate by check mark whether the registrants are a shell company (as defined in Rule 12b-2 of the Exchange Act). YES ¨ NO x

Aggregate market value of the voting stock held by non-affiliates of the registrants as of June 29, 2007:

Energen Corporation	$3,886,440,012

Indicate number of shares outstanding of each of the registrant s classes of common stock as of February 5, 2008:

Energen Corporation	71,681,985 shares
Alabama Gas Corporation	1,972,052 shares

Alabama Gas Corporation meets the conditions set forth in General Instruction I(1) (a) and (b) of Form 10-K and is therefore filing this form with the reduced disclosure format pursuant to General Instruction I(2).

DOCUMENTS INCORPORATED BY REFERENCE

Energen Corporation Proxy Statement to be filed on or about March 24, 2008 (Part III, Item 10-14)

INDUSTRY GLOSSARY

For a more complete definition of certain terms defined below, as well as other terms and concepts applicable to successful efforts accounting, please refer to Rule 4-10(a) of Regulation S-X, promulgated pursuant to the Securities Act of 1933 and the Securities Exchange Act of 1934, each as amended.

Basis	The difference between the futures price for a commodity and the corresponding cash spot price. This commonly is related to factors such as product quality, location and contract pricing.
Basin-Specific	A type of derivative contract whereby the contract s settlement price is based on specific geographic basin indices.
Behind Pipe Reserves	Oil or gas reserves located above or below the currently producing zone(s) that cannot be extracted until a recompletion or pay-add occurs.
Call Option	A contract that gives the investor the right, but not the obligation, to buy the underlying commodity at a certain price on an agreed upon date.
Carried Interest	An agreement under which one party agrees to pay for a specified portion or for all of the development and operating costs of another party on a property in which both own a portion of the working interest.
Cash Flow Hedge	The designation of a derivative instrument to reduce exposure to variability in cash flows from the forecasted sale of oil, gas or natural gas liquids production whereby the gains (losses) on the derivative transaction are anticipated to offset the losses (gains) on the forecasted sale.
Collar	A financial arrangement that effectively establishes a price range between a floor and a ceiling for the underlying commodity. The purchaser bears the risk of fluctuation between the minimum (or floor) price and the maximum (or ceiling) price.
Development Costs	Costs necessary to gain access to, prepare and equip development wells in areas of proved reserves.
Development Well	A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.
Downspacing	An increase in the number of available drilling locations as a result of a regulatory commission order.
Dry Well	An exploratory or a development well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.
Exploration Expenses	Costs primarily associated with drilling unsuccessful exploratory wells in undeveloped properties, exploratory geological and geophysical activities, and costs of impaired and expired leaseholds.
Exploratory Well	A well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir.
Futures Contract	An exchange-traded legal contract to buy or sell a standard quantity and quality of a commodity at a specified future date and price. Such contracts offer liquidity and minimal credit risk exposure but lack the flexibility of swap contracts.
Hedging	The use of derivative commodity instruments such as futures, swaps and collars to help reduce financial exposure to commodity price volatility.
Gross Revenues	Revenues reported after deduction of royalty interest payments.
Gross Well or Acre	A well or acre in which a working interest is owned.
Liquified Natural Gas (LNG)	Natural gas that is liquified by reducing the temperature to negative 260 degrees Fahrenheit. LNG typically is used to supplement traditional natural gas supplies during periods of peak demand.
Long-Lived Reserves	Reserves generally considered to have a productive life of approximately 10 years or more, as measured by the reserves-to-production ratio.

Natural Gas Liquids (NGL)	Liquid hydrocarbons that are extracted and separated from the natural gas stream. NGL products include ethane, propane, butane, natural gasoline and other hydrocarbons.
Net Well or Acre	A net well or acre is deemed to exist when the sum of fractional ownership working interests in gross wells or acres equals one.
Odorization	The adding of odorant to natural gas which is a characteristic odor so that leaks can be readily detected by smell.
Operational Enhancement	Any action undertaken to improve production efficiency of oil and gas wells and/or reduce well costs.
Operator	The company responsible for exploration, development and production activities for a specific project.
Pay-Add	An operation within a currently producing wellbore that attempts to access and complete an additional pay zone(s) while maintaining production from the existing completed zone(s).
Pay Zone	The formation from which oil and gas is produced.
Production (Lifting) Costs	Costs incurred to operate and maintain wells.
Productive Well	An exploratory or a development well that is not a dry well.
Proved Developed Reserves	The portion of proved reserves which can be expected to be recovered through existing wells with existing equipment and operating methods.
Proved Reserves	Estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.
Proved Undeveloped Reserves (PUD)	The portion of proved reserves which can be expected to be recovered from new wells on undrilled proved acreage or from existing wells where a relatively major expenditure is required for completion.
Put Option	A contract that gives the purchaser the right, but not the obligation, to sell the underlying commodity at a certain price on an agreed date.
Recompletion	An operation within an existing wellbore whereby a completion in one pay zone is abandoned in order to attempt a completion in a different pay zone.
Reserves-to-Production Ratio	Ratio expressing years of supply determined by dividing the remaining recoverable reserves at year end by actual annual production volumes. The reserve-to-production ratio is a statistical indicator with certain limitations, including predictive value. The ratio varies over time as changes occur in production levels and remaining recoverable reserves.
Secondary Recovery	The process of injecting water, gas, etc., into a formation in order to produce additional oil otherwise unobtainable by initial recovery efforts.
Service Well	A well employed for the introduction into an underground stratum of water, gas or other fluid under pressure or disposal of salt water produced with oil or other waste.
Sidetrack Well	A new section of wellbore drilled from an existing well.

Swap	A contractual arrangement in which two parties, called counterparties, effectively agree to exchange or swap variable and fixed rate payment streams based on a specified commodity volume. The contracts allow for flexible terms such as specific quantities, settlement dates and location but also expose the parties to counterparty credit risk.
Transportation	Moving gas through pipelines on a contract basis for others.
Throughput	Total volumes of natural gas sold or transported by the gas utility.
Working Interest	Ownership interest in the oil and gas properties that is burdened with the cost of development and operation of the property.
Workover	A major remedial operation on a completed well to restore, maintain, or improve the well s production such as deepening the well or plugging back to produce from a shallow formation.
-e	Following a unit of measure denotes that the oil and natural gas liquids components have been converted to cubic feet equivalents at a rate of 6 thousand cubic feet per barrel.

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This Form 10-K is filed on behalf of Energen Corporation (Energen or the Company)

and Alabama Gas Corporation (Alagasco).

Forward-Looking Statements: *Certain statements in this report express expectations of future plans, objectives and performance of the Company and its subsidiaries and constitute forward-looking statements made pursuant to the Safe Harbor provision of the Private Securities Litigation Reform Act of 1995. Except as otherwise disclosed, the forward-looking statements do not reflect the impact of possible or pending acquisitions, investments, divestitures or restructurings. The absence of errors in input data, calculations and formulas used in estimates, assumptions and forecasts cannot be guaranteed. Neither the Company nor Alagasco undertakes any obligation to correct or update any* *forward-looking statements whether as a result of new information, future events or otherwise.*

All statements based on future expectations rather than on historical facts are forward-looking statements that are dependent on certain events, risks and uncertainties that could cause actual results to differ materially from those anticipated. Some of these include, but are not limited to, economic and competitive conditions, inflation rates, legislative and regulatory changes, financial market conditions, our ability to access the capital markets, future business decisions, utility customer growth and retention and usage per customer, litigation results and other uncertainties, all of which are difficult to predict.

Third Party Facilities: The forward-looking statements also assume generally uninterrupted access to third party oil and gas gathering, transportation, processing and storage facilities. Energen Resources Corporation, the Company s oil and gas subsidiary, relies upon such facilities for access to markets for its production. Alagasco relies upon such facilities for access to natural gas supplies. Such facilities are typically limited in number and geographically concentrated. An extended interruption of access to or service from these facilities, whether caused by weather events, natural disaster, accident, mechanical failure, criminal act or otherwise, could result in material adverse financial consequences to Alagasco, Energen Resources and/or the Company.

Energen Resources Production and Drilling: There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and in projecting future rates of production and timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates. In the event Energen Resources is unable to fully invest its planned acquisition, development and exploratory expenditures, future operating revenues, production, and proved reserves could be negatively affected. The drilling of development and exploratory wells can involve significant risks, including those related to timing, success rates and cost overruns, and these risks can be affected by lease and rig availability, complex geology and other factors. Anticipated drilling plans and capital expenditures may also change due to weather, manpower and equipment availability, changing emphasis by management and a variety of other factors which could result in actual drilling and capital expenditures being substantially different than currently planned.

Energen Resources Hedging: Although Energen Resources makes use of futures, swaps, options and fixed-price contracts to mitigate price risk, fluctuations in future oil, gas and natural gas liquids prices could materially affect the Company s financial position, results of operations and cash flows; furthermore, such risk mitigation activities may cause the Company s financial position and results of operations to be materially different from results that would have been obtained had such risk mitigation activities not occurred. The effectiveness of such risk mitigation assumes that counterparties maintain satisfactory credit quality. The effectiveness of such risk mitigation also assumes that actual sales volumes will generally meet or exceed the volumes subject to the futures, swaps, options and fixed-price contracts. A substantial failure to meet sales volume targets, whether caused by miscalculations, weather events, natural disaster, accident, mechanical failure, criminal act or otherwise, could leave Energen Resources financially exposed to its counterparties and result in material adverse financial consequences to Energen Resources and the Company. The adverse effect could be increased if the adverse event was widespread enough to move market prices against Energen Resources position.

Alagasco s Hedging: Similarly, although Alagasco makes use of futures, swaps and fixed-price contracts to mitigate gas supply cost risk, fluctuations in future gas supply costs could materially affect its financial position and rates to customers. The effectiveness of Alagasco s risk mitigation assumes that its counterparties in such activities maintain satisfactory credit quality. The effectiveness of such risk mitigation also assumes that Alagasco s actual gas supply needs will generally meet or exceed the volumes subject to the futures, swaps and

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fixed-price contracts. A substantial failure to experience projected gas supply needs, whether caused by miscalculations, weather events, natural disaster, accident, mechanical failure, criminal act or otherwise, could leave Alagasco financially exposed to its counterparties and result in material adverse financial consequences to Alagasco and the Company. The adverse effect could be increased if the adverse event was widespread enough to move market prices against Alagasco s position.

Operations: Inherent in the oil and gas production activities of Energen Resources and the gas distribution activities of Alagasco are a variety of hazards and operation risks, such as leaks, explosions and mechanical problems that could cause substantial financial losses. In addition, these risks could result in loss of human life, significant damage to property, environmental pollution, impairment of our operations and substantial losses to the Company. In accordance with customary industry practices, the Company maintains insurance against some, but not all, of these risks and losses. The location of pipeline and storage facilities near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from these risks. The occurrence of any of these events could adversely affect Alagasco s, Energen Resources and/or the Company s financial position, results of operations and cash flows.

Alagasco s Service Territory: Alagasco s utility customers are geographically concentrated in central and north Alabama. Significant economic, weather, natural disaster, criminal act or other events that adversely affect this region could adversely affect Alagasco and the Company.

PART I

ITEM 1. BUSINESS
General

Energen Corporation, based in Birmingham, Alabama, is a diversified energy holding company engaged primarily in the development, acquisition, exploration and production of oil, natural gas and natural gas liquids in the continental United States and in the purchase, distribution and sale of natural gas in central and north Alabama. Its two principal subsidiaries are Energen Resources Corporation and Alabama Gas Corporation (Alagasco).

Alagasco was formed in 1948 by the merger of Alabama Gas Company into Birmingham Gas Company, the predecessors of which had been in existence since the mid-1800s. Alagasco became publicly traded in 1953. Energen Resources was formed in 1971 as a subsidiary of Alagasco. Energen was incorporated in 1978 in preparation for the 1979 corporate reorganization in which Alagasco and Energen Resources became subsidiaries of Energen.

The Company maintains a Web site with the address *www.energen.com*. The Company does not include the information contained on its Web site as part of this report nor is the information incorporated by reference into this report. The Company makes available free of charge through its Web site the annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to these reports. Also, these reports are available in print upon shareholder request. These reports are available as soon as reasonably practicable after being electronically filed with or furnished to the Securities and Exchange Commission. The Company s Web site also includes its Code of Ethics, Corporate Governance Guidelines, Audit Committee Charter, Officers Review Committee Charter, Governance and Nominations Committee Charter and Finance Committee Charter, each of which is available in print upon shareholder request.

Financial Information About Industry Segments

The information required by this item is provided in Note 19, Industry Segment Information, in the Notes to Financial Statements.

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Narrative Description of Business

Oil and Gas Operations

General: Energen s oil and gas operations focus on increasing production and adding proved reserves through the development and acquisition of oil and gas properties. In addition, Energen Resources explores for and develops new reservoirs, primarily in areas in which it has an operating presence. All gas, oil and natural gas liquids production is sold to third parties. Energen Resources also provides operating services in the Black Warrior, San Juan and Permian basins for its joint interest and third parties. These services include overall project management and day-to-day decision-making relative to project operations.

At the end of 2007, Energen Resources proved oil and gas reserves totaled 1,754 billion cubic feet equivalent (Bcfe). Substantially all of these reserves are located in the San Juan Basin in New Mexico and Colorado, the Permian Basin in west Texas and the Black Warrior Basin in Alabama. Approximately 82 percent of Energen Resources year-end reserves are proved developed reserves. Energen Resources reserves are long-lived, with a year-end reserves-to-production ratio of 18 years. Natural gas represents approximately 64 percent of Energen Resources proved reserves, with oil representing approximately 26 percent and natural gas liquids comprising the balance.

Growth Strategy: Energen has operated for more than ten years under a strategy to grow its oil and gas operations. Since the end of fiscal year 1995, Energen Resources has invested approximately $1.2 billion in property acquisitions, $1.3 billion in related development, and $209 million in exploration and related development. Energen Resources capital investment in 2008 and 2009 is currently expected to approximate $579 million primarily for existing properties. The Company also may allocate additional capital during this two-year period for other oil and gas activities such as property acquisitions and the exploration and development of potential shale plays primarily in Alabama. The estimates above do not include amounts for capital related to potential acquisitions or development of these shale plays discussed below.

Energen Resources seeks to acquire onshore North American properties which offer proved undeveloped and/or behind-pipe reserves as well as operational enhancement potential. Energen Resources prefers properties with long-lived reserves and multiple pay-zone opportunities; however, Energen Resources will consider acquisitions of other types of properties which meet its investment requirements, including acquisitions with unproved properties. In addition, Energen Resources conducts exploration activities primarily in areas in which it has operations and remains open to exploration activities which complement its core expertise and meet its investment requirements. Following an acquisition, Energen Resources focuses on increasing production and reserves through development of the properties undeveloped reserves and behind-pipe reserve potential as well as engaging in other activities. These activities include development well drilling, exploration, behind-pipe recompletions, pay-adds, workovers, secondary recovery and operational enhancements. Energen Resources prefers to operate its properties in order to better control the nature and pace of development activities. Energen Resources operated approximately 91 percent of its proved reserves at December 31, 2007.

In October 2006, Energen Resources sold to Chesapeake Energy Corporation (Chesapeake) a 50 percent interest in its unproved lease position of approximately 200,000 acres in various shale plays in Alabama for $75 million and a $15 million carried drilling interest. In addition, the two companies signed an agreement to form an area of mutual interest (AMI) through which they will pursue new leases, exploration, development and operations on a 50-50 basis, for at least the next 10 years. Energen Resources and Chesapeake continue to lease shared acreage in the AMI, which encompasses Alabama and some of Georgia, in advance of drilling. As of February 25, 2008, Energen Resources net acreage position in Alabama shale totaled approximately 287,500 acres and represents multiple shale opportunities.

Energen Resources development activities can result in the addition of new proved reserves and can serve to reclassify proved undeveloped reserves to proved developed reserves. Proved reserve disclosures are provided annually, although changes to reserve classifications occur throughout the year. Accordingly, additions of new reserves from development activities can occur throughout the year and may result from numerous factors including, but not limited to, regulatory approvals for drilling unit downspacing that increase the number of

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available drilling locations; changes in the economic or operating environments that allow previously uneconomic locations to be added; technological advances that make reserve locations available for development; successful development of existing proved undeveloped reserve locations that reclassify adjacent probable locations to proved undeveloped reserve locations; increased knowledge of field geology and engineering parameters relative to oil and gas reservoirs; and changes in management s intent to develop certain opportunities.

During the three years ended December 31, 2007, the Company s development efforts have added 364 Bcfe of proved reserves from the drilling of 975 gross development wells (including 27 sidetrack wells) and 150 well recompletions and pay-adds. In 2007, Energen Resources successful development wells and other activities added approximately 127 Bcfe of proved reserves; the company drilled 367 gross development wells (including 22 sidetrack wells), performed some 34 well recompletions and pay-adds, and conducted other operational enhancements. Energen Resources production from continuing operations totaled 98.6 Bcfe in 2007 and is estimated to total 102 Bcfe in 2008, including 100 Bcfe of estimated production from proved reserves owned at December 31, 2007. In 2009, production is estimated to be 108 Bcfe, including approximately 100 Bcfe produced from proved reserves currently owned.

Drilling Activity: The following table sets forth the total number of net productive and dry exploratory and development wells drilled:

Years ended December 31,	**2007**	2006	2005
Development:			
Productive	**135.5**	151.7	153.9
Dry	**1.0**	-	1.7
Total	**136.5**	151.7	155.6
Exploratory:			
Productive	**21.7**	40.1	4.1
Dry	**0.3**	3.0	-
Total	**22.0**	43.1	4.1

As of December 31, 2007, the Company was participating in the drilling of 9 gross development wells, with the Company s interest equivalent to 5 wells. In addition to the development wells drilled, the Company drilled 99.8, 35.9 and 33 net service wells during 2007, 2006 and 2005, respectively. As of December 31, 2007, the Company was participating in the drilling of 1 gross service well, with the Company s interest equivalent to 0.9 well.

Productive Wells and Acreage: The following table sets forth the total gross and net productive gas and oil wells as of December 31, 2007, and developed and undeveloped acreage as of the latest practicable date prior to year-end:

	Gross	Net
Gas wells	4,101	2,333
Oil wells	3,161	1,587
Developed acreage	820,732	564,748
Undeveloped acreage	324,395	287,852

There were 17 wells with multiple completions in 2007. All wells and acreage are located onshore in the United States, with the majority of the net undeveloped acreage located in Alabama.

Risk Management: Energen Resources attempts to lower the commodity price risk associated with its oil and natural gas business through the use of futures, swaps and options. Energen Resources does not hedge more than 80 percent of its estimated annual production and generally does not hedge more than two fiscal years forward. Statement of Financial Accounting Standards (SFAS) No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended requires all derivatives to be recognized on the balance sheet and measured at fair value. If a derivative is designated as a cash flow hedge, the effectiveness of the hedge, or the

degree that the gain (loss) for the hedging instrument offsets the loss (gain) on the hedged item, is measured at each reporting period. The effective portion of the gain or loss on the derivative instrument is recognized in other comprehensive income as a component of equity and subsequently reclassified into earnings when the forecasted transaction affects earnings. The ineffective portion of a derivative s change in fair value is required to be recognized in earnings immediately. Derivatives that do not qualify for hedge treatment under SFAS No. 133 must be recorded at fair value with gains or losses recognized in operating revenues in the period of change.

The Company may also enter into derivative transactions that do not qualify for cash flow hedge accounting but are considered by management to represent valid economic hedges and are accounted for as mark-to-market transactions. These economic hedges may include, but are not limited to, put options and swaps on non-operated or other properties for which all of the necessary information to qualify for cash flow hedge accounting is either not readily available or subject to change.

In the case of an acquisition, Energen Resources may hedge more than two years forward to protect targeted returns. Energen Resources prefers long-lived reserves and primarily uses the then-current oil and gas futures prices in its evaluation models, the prevailing swap curve and, for the longer-term, its own pricing assumptions.

See the Forward-Looking Statements in Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations, and Item 1A, Risk Factors, for further discussion with respect to price and other risks.

Natural Gas Distribution

General: Alagasco is the largest natural gas distribution utility in the state of Alabama. Alagasco purchases natural gas through interstate and intrastate marketers and suppliers and distributes the purchased gas through its distribution facilities for sale to residential, commercial and industrial customers and other end-users of natural gas. Alagasco also provides transportation services to industrial and commercial customers located on its distribution system. These transportation customers, using Alagasco as their agent or acting on their own, purchase gas directly from producers, marketers or suppliers and arrange for delivery of the gas into the Alagasco distribution system. Alagasco charges a fee to transport such customer-owned gas through its distribution system to the customers facilities.

Alagasco s service territory is located in central and parts of north Alabama and includes 177 cities and communities in 28 counties. The aggregate population of the counties served by Alagasco is estimated to be 2.4 million. Among the cities served by Alagasco are Birmingham, the center of the largest metropolitan area in Alabama, and Montgomery, the state capital. During 2007, Alagasco served an average of 416,967 residential customers and 34,200 commercial, industrial and transportation customers. The Alagasco distribution system includes approximately 10,200 miles of main and more than 11,900 miles of service lines, odorization and regulation facilities, and customer meters.

APSC Regulation: As an Alabama utility, Alagasco is subject to regulation by the Alabama Public Service Commission (APSC) which established the Rate Stabilization and Equalization (RSE) rate-setting process in 1983. RSE was extended in 2007, 2002, 1996, 1990, 1987 and 1985. On December 21, 2007, the APSC extended RSE for a seven-year period through December 31, 2014. Under the terms of the extension, RSE will continue after December 31, 2014, unless, after notice to the Company and a hearing, the APSC votes to modify or discontinue the RSE methodology. Alagasco s allowed range of return on average equity remains 13.15 percent to 13.65 percent throughout the term of the order. Alagasco is on a September 30 fiscal year for rate-setting purposes (rate year).

Under RSE, the APSC conducts quarterly reviews to determine, based on Alagasco s projections and year-to-date performance, whether Alagasco s return on average equity at the end of the rate year will be within the allowed range of return. Reductions in rates can be made quarterly to bring the projected return within the allowed range; increases, however, are allowed only once each rate year, effective December 1, and cannot exceed 4 percent of prior-year revenues. Prior to the December 21, 2007 extension, RSE limited the utility s equity upon which a return is permitted to 60 percent of total capitalization and provided for certain cost control

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measures designed to monitor Alagasco s operations and maintenance (O&M) expense. Under the inflation-based cost control measurement established by the APSC, if the percentage change in O&M expense per customer fell within a range of 1.25 points above or below the percentage change in the Consumer Price Index For All Urban Consumers (index range), no adjustment was required. If the change in O&M expense per customer exceeded the index range, three-quarters of the difference was returned to customers. To the extent the change was less than the index range, the utility benefited by one-half of the difference through future rate adjustments.

Subsequent to the extension, the equity on which a return will be permitted will be phased down to 57 percent by December 31, 2008 and 55 percent by December 31, 2009. The changes to the O&M expense cost control measurement subsequent to the extension are as follows: annual changes in O&M expense will be measured on an aggregate basis rather than per customer; the percentage change in O&M expense must fall within a range of 0.75 points above or below the percentage change in the index range; non-recurring and/or recurring items that fluctuate based on situations demonstrated to be beyond Alagasco s control may be excluded for the cost control measurement calculation; the O&M expense base for measurement purposes will continue to be set at the prior year s actual O&M expense amount unless the Company exceeds the top of the index range in two successive years, in which case the base for the following year will be set at the top of the index range.

The temperature adjustment rider to Alagasco s rate tariff, approved by the APSC in 1990, was designed to mitigate the earnings impact of variances from normal temperatures. Alagasco calculates a temperature adjustment to customers monthly bills to moderate the impact of departures from normal temperatures on Alagasco s earnings. This adjustment, however, is subject to certain limitations including regulatory limits on adjustments to increase customers bills. Other non-temperature weather conditions that may affect customer usage are not included such as the impact of wind velocity or cloud cover and the impact of any elasticity of demand as a result of high commodity prices. Adjustments to customers bills are made in the same billing cycle in which the weather variation occurs. Substantially all the customers to whom the temperature adjustment applies are residential, small commercial and small industrial. Alagasco s rate schedules for natural gas distribution charges contain a Gas Supply Adjustment (GSA) rider that permits the pass-through to customers of changes in the cost of gas supply.

The APSC approved an Enhanced Stability Reserve (ESR) beginning October 1997, with an approved maximum funding level of $4 million, to which Alagasco may charge the full amount of: (1) extraordinary O&M expenses resulting from *force majeure* events such as storms, severe weather, and outages, when one or a combination of two such events results in more than $200,000 of additional O&M expense during a rate year; or (2) individual industrial and commercial customer revenue losses that exceed $250,000 during the rate year, if such losses cause Alagasco s return on equity to fall below 13.15 percent. Following a year in which a charge against the ESR is made, the APSC provides for accretions to the ESR in an amount of no more than $40,000 monthly until the maximum funding level is achieved. Subsequent to the 2007 extension, Alagasco will not have accretions against the ESR until December 31, 2010 unless the Company incurs a significant natural disaster during the three-year period ended December 31, 2010 and receives approval from the APSC to resume accretions under the ESR.

Gas Supply: Alagasco s distribution system is connected to two major interstate natural gas pipeline systems, Southern Natural Gas Company (Southern) and Transcontinental Gas Pipe Line Company (Transco). It is also connected to several intrastate natural gas pipeline systems and to Alagasco s two liquified natural gas (LNG) facilities.

Alagasco purchases natural gas from various natural gas producers and marketers. Certain volumes are purchased under firm contractual commitments with other volumes purchased on a spot market basis. The purchased volumes are delivered to Alagasco s system using a variety of firm transportation, interruptible transportation and storage capacity arrangements designed to meet the system s varying levels of demand. Alagasco s LNG facilities can provide the system with up to an additional 200,000 thousand cubic feet per day (Mcfd) of natural gas to meet peak day demand.

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As of December 31, 2007, Alagasco had the following contracts in place for firm natural gas pipeline transportation and storage services:

	December 31, 2007 (Mcfd)
Southern firm transportation	152,933
Southern storage and no notice transportation	251,679
Transco firm transportation	70,000
Various intrastate transportation	20,240

Competition and Rate Flexibility: The price of natural gas is a significant competitive factor in Alagasco s service territory, particularly among large commercial and industrial transportation customers. Propane, coal and fuel oil are readily available, and many industrial customers have the capability to switch to alternate fuels and/or alternate sources of gas. In the residential and small commercial and industrial markets, electricity is the principal competitor. With the support of the APSC, Alagasco has implemented a variety of flexible rate strategies to help it compete for the large customer gas load in the marketplace. Rate flexibility remains critical as the utility faces competition for this load. To date, the utility has been effective in utilizing its flexible rate strategies to minimize bypass and price-based switching to alternate fuels and alternate sources of gas.

In 1994 Alagasco implemented the P Rate in response to the competitive challenge of interstate pipeline capacity release. Under this tariff provision, Alagasco releases much of its excess pipeline capacity and repurchases it as agent for its transportation customers under 12 month contracts. The transportation customers benefit from lower pipeline costs; Alagasco s core market customers benefit, as well, since the utility uses the revenues received from the P Rate to decrease gas costs for its residential and its small commercial and industrial customers. In 2007, approximately 300 of Alagasco s transportation customers utilized the P Rate, and the resulting reduction in core market gas costs totaled more than $7.8 million.

The Competitive Fuel Clause (CFC) and Transportation Tariff also have been important to Alagasco s ability to compete effectively for customer load in its service territory. The CFC allows Alagasco to adjust large customer rates on a case-by-case basis to compete with alternate fuels and alternate sources of gas. The GSA rider to Alagasco s tariff allows the Company to recover a reduction in charges allowed under the CFC because the retention of any customer, particularly large commercial and industrial transportation customers, benefits all customers by recovering a portion of the system s fixed costs. The Transportation Tariff allows Alagasco to transport gas for customers, rather than buy and resell it to them, and is based on Alagasco s sales profit margin so that operating margins are unaffected. During 2007 substantially all of Alagasco s large commercial and industrial customer deliveries involved the transportation of customer-owned gas. In addition, Alagasco served as gas purchasing agent for more than 99 percent of its transportation customers. Alagasco also uses long-term special contracts as a vehicle for retaining large customer load. At the end of 2007, 65 of the utility s largest commercial and industrial transportation customers were under special contracts of varying lengths.

Natural gas service available to Alagasco customers falls into two broad categories: interruptible and firm. Interruptible service contractually is subject to interruption by Alagasco for various reasons; the most common occurrence is curtailment of industrial customers during periods of peak core market heating demand. Interruptible service typically is provided to large commercial and industrial transportation customers who can reduce their gas consumption by adjusting production schedules or by switching to alternate fuels for the duration of the service interruption. More expensive firm service, on the other hand, generally is not subject to interruption and is provided to residential and to small commercial and industrial customers; these core market customers depend on natural gas primarily for space heating.

Growth: Customer growth presents a major challenge for Alagasco, given its mature, slow-growth service area. In 2007 Alagasco s average number of customers decreased 1 percent. Alagasco will continue to concentrate on maintaining its current penetration levels in the residential new construction market and generating additional revenue in the small and large commercial and industrial market segments.

Seasonality: Alagasco s gas distribution business is highly seasonal since a material portion of the utility s total sales and delivery volumes is to space heating customers. Alagasco s rate tariff includes a temperature adjustment rider primarily for residential, small commercial and small industrial customers that moderates the impact of departures from normal temperatures on Alagasco s earnings. The calculation is performed monthly, and adjustments are made to customers bills in the actual month the weather variation occurs.

Environmental Matters

Various environmental laws and regulations apply to the operations of Energen Resources and Alagasco. Historically, the cost of environmental compliance has not materially affected the Company s financial position, results of operations or cash flows and is not expected to do so in the future; however, new regulations, enforcement policies, claims for damages or other events could result in significant unanticipated costs.

A discussion of certain litigation against Energen Resources in the state of Louisiana related to the restoration of oilfield properties is included in Item 3, Legal Proceedings of Part I in this Form 10-K.

Alagasco is in the chain of title of nine former manufactured gas plant sites (four of which it still owns) and five manufactured gas distribution sites (one of which it still owns). An investigation of the sites does not indicate the present need for remediation activities. Management expects that, should remediation of any such sites be required in the future, Alagasco s share, if any, of such costs will not materially affect the Company s financial position.

Employees

The Company has approximately 1,542 employees, of which Alagasco employs 1,169 and Energen Resources employs 373. The Company believes that its relations with employees are good.

ITEM 1A. RISK FACTORS

Third Party Facilities: Energen Resources delivers to and Alagasco is served by third party facilities. These facilities include third party oil and gas gathering, transportation, processing and storage facilities. Energen Resources relies upon such facilities for access to markets for its production. Alagasco relies upon such facilities for access to natural gas supplies. Such facilities are typically limited in number and geographically concentrated. An extended interruption of access to or service from these facilities, whether caused by weather events, natural disaster, accident, mechanical failure, criminal act or otherwise could result in material adverse financial consequences to Alagasco, Energen Resources and/or the Company.

Energen Resources Production and Drilling: There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and in projecting future rates of production and timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates. In the event Energen Resources is unable to fully invest its planned development, acquisition and exploratory expenditures, future operating revenues, production, and proved reserves could be negatively affected. The drilling of development and exploratory wells can involve significant risks, including those related to timing, success rates and cost overruns, and these risks can be affected by lease and rig availability, complex geology and other factors. Anticipated drilling plans and capital expenditures may also change due to weather, manpower and equipment availability, changing emphasis by management and a variety of other factors which could result in actual drilling and capital expenditures being substantially different than currently planned.

Energen Resources Hedging: Although Energen Resources makes use of futures, swaps, options and fixed-price contracts to mitigate price risk, fluctuations in future oil, gas and natural gas liquids prices could materially affect the Company s financial position, results of operations and cash flows; furthermore, such risk mitigation activities may cause the Company s financial position and results of operations to be materially different from results that would have been obtained had such risk mitigation activities not occurred. The effectiveness of such risk mitigation assumes that counterparties maintain satisfactory credit quality. The effectiveness of such risk mitigation also assumes that actual sales volumes will generally meet or exceed the volumes subject to the futures, swaps, options and fixed-price contracts. A substantial failure to meet sales volume targets, whether caused by miscalculations, weather events, natural disaster, accident, mechanical failure, criminal act or otherwise, could leave Energen Resources financially exposed to its counterparties and result in material adverse financial consequences to Energen Resources and the Company. The adverse effect could be increased if the adverse event was widespread enough to move market prices against Energen Resources position.

Alagasco s Hedging: Similarly, although Alagasco makes use of futures, swaps and fixed-price contracts to mitigate gas supply cost risk, fluctuations in future gas supply costs could materially affect its financial position and rates to customers. The effectiveness of Alagasco s risk mitigation assumes that its counterparties in such activities maintain satisfactory credit quality. The effectiveness of such risk mitigation also assumes that Alagasco s actual gas supply needs will generally meet or exceed the volumes subject to the futures, swaps and fixed-price contracts. A substantial failure to experience projected gas supply needs, whether caused by miscalculations, weather events, natural disaster, accident, mechanical failure, criminal act or otherwise, could leave Alagasco financially exposed to its counterparties and result in material adverse financial consequences to Alagasco and the Company. The adverse effect could be increased if the adverse event was widespread enough to move market prices against Alagasco s position.

Operations: Inherent in the gas distribution activities of Alagasco and the oil and gas production activities of Energen Resources are a variety of hazards and operation risks, such as leaks, explosions and mechanical problems that could cause substantial financial losses. In addition, these risks could result in loss of human life, significant damage to property, environmental pollution, impairment of operations and substantial losses to the Company. In accordance with customary industry practices, the Company maintains insurance against some, but not all, of these risks and losses. The location of pipeline and storage facilities near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from these risks. The occurrence of any of these events could adversely affect Alagasco s, Energen Resources and/or the Company s financial position, results of operations and cash flows.

Energen Resources Customer Concentration: Revenues and related accounts receivable from oil and gas operations primarily are generated from the sale of produced oil, natural gas and natural gas liquids to energy marketing companies. Such sales are typically made on an unsecured credit basis with payment due the month following delivery. This concentration of sales to the energy marketing industry has the potential to affect the Company s overall exposure to credit risk, either positively or negatively, in that the Company s oil and gas purchasers may be affected similarly by changes in economic, industry or other conditions. Energen Resources considers the credit quality of its customers and, in certain instances, may require credit assurances such as a deposit, letter of credit or parent guarantee. The four largest oil, natural gas and natural gas liquids purchasers account for approximately 22 percent, 14 percent, 11 percent and 10 percent, respectively, of Energen Resources estimated 2008 production. Energen Resources other purchasers each bought less than 8 percent of production.

Alagasco s Service Territory: Alagasco s utility customers are geographically concentrated in central and north Alabama. Significant economic, weather, natural disaster, criminal act or other events that adversely affect this region could adversely affect Alagasco and the Company.

Access to Credit Markets: The Company and its subsidiaries rely on access to credit markets. The availability and cost of credit market access is significantly influenced by rating agency evaluations of the Company and of Alagasco. Events affecting credit market liquidity could increase borrowing costs or limit availability of funds.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None

ITEM 2. PROPERTIES

The corporate headquarters of Energen, Alagasco and Energen Resources are located in leased office space in Birmingham, Alabama. See the discussion under Item 1-Business for further information related to Energen Resources and Alagasco s business operations. Information concerning Energen Resources production and reserves is summarized in the table below and included in Note 18, Oil and Gas Operations (Unaudited), in the Notes to Financial Statements. See Item 7 -Management s Discussion and Analysis of Financial Condition and Results of Operations for a discussion of the future outlook and expectations for Energen Resources and Alagasco.

Oil and Gas Operations

Energen Resources focuses on increasing its production and proved reserves through the acquisition and development of onshore North American producing oil and gas properties. Energen Resources maintains offices in Arcadia, Louisiana; in Farmington, New Mexico; and in Midland, Texas. The Company also maintains offices in Lehman, Seminole, Westbrook and Penwell, Texas; and in Brookwood and Tuscaloosa, Alabama.

The major areas of operations include (1) the San Juan Basin, (2) the Permian Basin, (3) the Black Warrior Basin and (4) North Louisiana/East Texas as highlighted on the above map.

The following table sets forth the production volumes for the year ended December 31, 2007, and proved reserves and reserves-to-production ratio by area as of December 31, 2007:

	Year Ended		
	December 31, 2007	**December 31, 2007**	**December 31, 2007**

	Production Volumes (MMcfe)	Proved Reserves (MMcfe)	Reserves-to-Production Ratio
San Juan Basin	47,517	943,423	19.85 years
Permian Basin	28,655	501,920	17.52 years
Black Warrior Basin	14,813	234,253	15.81 years
North Louisiana/East Texas	7,187	68,653	9.55 years
Other	433	5,403	12.48 years
Total	98,605	1,753,652	17.78 years

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The following table sets forth proved reserves by area as of December 31, 2007:

	Gas MMcf	Oil MBbl	NGL MBbl
San Juan Basin	762,091	1,326	28,896
Permian Basin	47,648	72,944	2,768
Black Warrior Basin	234,253	-	-
North Louisiana/East Texas	67,573	180	-
Other	4,353	175	-
Total	1,115,918	74,625	31,664

The following table sets forth proved developed reserves by area as of December 31, 2007:

	Gas MMcf	Oil MBbl	NGL MBbl
San Juan Basin	569,800	1,320	25,805
Permian Basin	44,042	59,553	2,543
Black Warrior Basin	231,791	-	-
North Louisiana/East Texas	53,526	161	-
Other	4,351	175	-
Total	903,510	61,209	28,348

Energen Resources files Form EIA-23 with the Department of Energy which reports gross proved reserves, including the working interest share of other owners, for properties operated by the Company. The proved reserves reported in the table above represent our share of proved reserves for all properties, based on our ownership interest in each property. For properties operated by Energen Resources, the difference between the proved reserves reported on Form EIA-23 and the gross reserves associated with the Company-owned proved reserves reported in the table above does not exceed five percent. Estimated proved reserves as of December 31, 2007 are based upon studies for each of our properties prepared by Company engineers and reviewed by Ryder Scott Company, L.P. and T. Scott Hickman and Associates, Inc., independent oil and gas reservoir engineers. Calculations were prepared using standard geological and engineering methods generally accepted by the petroleum industry and in accordance with SEC guidelines.

The following table sets forth the total net productive gas and oil wells by area as of December 31, 2007, and developed and undeveloped acreage as of the latest practicable date prior to year-end:

	Net Wells	Net Developed Acreage	Net Undeveloped Acreage
San Juan Basin	1,390	302,202	1,413
Permian Basin	1,579	87,851	3,309
Black Warrior Basin	782	147,190	1,187
North Louisiana/East Texas	159	20,675	55
Alabama Shale and Other	10	6,830	281,888
Total	3,920	564,748	287,852

Natural Gas Distribution

The properties of Alagasco consist primarily of its gas distribution system, which includes approximately 10,200 miles of main and more than 11,900 miles of service lines, odorization and regulation facilities, and customer meters. Alagasco also has two LNG facilities, four division commercial offices, three division business centers, two payment centers, three district offices, seven service centers, and other related property and equipment, some of which are leased by Alagasco.

ITEM 3. LEGAL PROCEEDINGS

Energen and its affiliates are, from time to time, parties to various pending or threatened legal proceedings. Certain of these lawsuits include claims for punitive damages in addition to other specific relief. Based upon information presently available, and in light of available legal and other defenses, contingent liabilities arising from threatened and pending litigation are not considered material in relation to the respective financial positions of Energen and its

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affiliates. It should be noted, however, that Energen and its affiliates conduct business in Alabama and other jurisdictions in which the magnitude and frequency of punitive or other damage awards may bear little or no relation to culpability or actual damages, thus making it difficult to predict litigation results.

Jefferson County, Alabama

In January 2006, RGGS Land and Minerals LTD, L.P. (RGGS) filed a lawsuit in Jefferson County, Alabama, alleging breach of contract with respect to Energen Resources calculation of certain allowed costs and failure to pay in a timely manner certain amounts due RGGS under a mineral lease. RGGS seeks a declaratory judgment with respect to the parties rights under the lease, reformation of the lease, monetary damages and termination of Energen Resources rights under the lease. The Occluded Gas Lease dated January 1, 1986 was originally between Energen Resources and United States Steel Corporation (U.S. Steel) as lessor. RGGS became the lessor under the lease as a result of a 2004 conveyance from U.S. Steel to RGGS. Approximately 120,000 acres in Jefferson and Tuscaloosa counties, Alabama, are subject to the lease. Separately on February 6, 2006, Energen Resources received notice of immediate lease termination from RGGS. During 2007, Energen Resources production associated with the lease was approximately 10.5 Bcf.

RGGS has adopted positions contrary to the seventeen years of course of dealing between Energen Resources and its original contracting partner, U.S. Steel. The Company believes that RGGS assertions are without merit and that the notice of lease termination is ineffective. Energen Resources intends to vigorously defend its rights under the lease. The Company remains in possession of the lease, believes that the likelihood of a judgment in favor of RGGS is remote, and has made no material accrual with respect to the litigation or purported lease termination.

Enron Corporation

Enron and Enron North America Corporation (ENA) have settled with Energen Resources and Alagasco related to the Enron and ENA bankruptcy proceedings. Under the settlement, Energen Resources was allowed claims in the bankruptcy cases against Enron and ENA of $12.5 million each. In December 2006, Energen Resources sold its claims against Enron and ENA for a gain of $6.7 million after-tax. All other claims have been released.

Legacy Litigation

During recent years, numerous lawsuits have been filed against oil production companies in Louisiana for restoration of oilfield properties. These suits are referred to in the industry as legacy litigation because they usually involve operations that were conducted on the affected properties many years earlier. Energen Resources is or has been a party to several legacy litigation lawsuits, most of which result from the operations of predecessor companies. Based upon information presently available, and in light of available legal and other defenses, contingent liabilities arising from legacy litigation in excess of the Company s accrued provision for estimated liability are not considered material to the Company s financial position.

Other

Various other pending or threatened legal proceedings are in progress currently, and the Company has accrued a provision for the estimated liability.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS
No matters were submitted to a vote of security holders during the fourth quarter of 2007.

EXECUTIVE OFFICERS OF THE REGISTRANTS

Energen Corporation

Name	Age	Position (1)
James T. McManus, II	49	Chairman, Chief Executive Officer and President of Energen and Chairman and Chief Executive Officer of Alagasco (2)
Wm. Michael Warren, Jr.	60	(3)
Charles W. Porter, Jr.	43	Vice President, Chief Financial Officer and Treasurer of Energen and Alagasco (4)
John S. Richardson	50	President and Chief Operating Officer of Energen Resources (5)
Dudley C. Reynolds	55	President and Chief Operating Officer of Alagasco (6)
J. David Woodruff, Jr.	51	General Counsel and Secretary of Energen and Alagasco and Vice President-Corporate Development of Energen (7)
Grace B. Carr	52	Vice President and Controller of Energen (8)

Notes: (1) All executive officers of Energen have been employed by Energen or a subsidiary for the past five years. Officers serve at the pleasure of the Board of Directors.

(2) Mr. McManus has been employed by the Company in various capacities since 1986. He was elected Executive Vice President and Chief Operating Officer of Energen Resources in October 1995 and President of Energen Resources in April 1997. He was elected President and Chief Operating Officer of Energen effective January 1, 2006 and Chief Executive Officer of Energen and each of its subsidiaries effective July 1, 2007. He was elected Chairman of the Board of Energen and each of its subsidiaries effective January 1, 2008. Mr. McManus serves as a Director of Energen and each of its subsidiaries.

(3) Mr. Warren retired from the Company at the end of 2007. He had been employed by the Company in various capacities since 1983 and served as Chairman of the Board and Chief Executive Officer of Energen and each of its subsidiaries since 1998. Mr. Warren was succeeded by Mr. McManus as Chief Executive officer effective July 1, 2007 and as Chairman of the Board of Energen and each of its subsidiaries effective January 1, 2008. Mr. Warren continues to serve as a Director of Energen and each of its subsidiaries.

(4) Mr. Porter has been employed by the Company in various financial capacities since 1989. He was elected Controller of Energen Resources in 1998. In 2001, he was elected Vice President Finance of Energen Resources. He was elected Vice President, Chief Financial Officer and Treasurer of Energen and each of its subsidiaries effective January 1, 2007.

(5) Mr. Richardson has been employed by the Company in various capacities since 1985. He was elected Vice President Acquisitions and Engineering of Energen Resources in 1997. He was elected Executive Vice President and Chief Operating Officer of Energen Resources effective January 1, 2006. He was elected President and Chief Operating Officer of Energen Resources effective January 23, 2008.

(6) Mr. Reynolds has been employed by the Company in various capacities since 1980. He was elected General Counsel and Secretary of Energen and each of its subsidiaries in April 1991. He was elected President and Chief Operating Officer of Alagasco effective January 1, 2003.

(7) Mr. Woodruff has been employed by the Company in various capacities since 1986. He was elected Vice President-Legal and Assistant Secretary of Energen and each of its subsidiaries in April 1991 and Vice President-Corporate Development of Energen in

October 1995. He was elected General Counsel and Secretary of Energen and each of its subsidiaries effective January 1, 2003.

(8) Ms. Carr was employed by the Company in various capacities from January 1985 to April 1989. She was not employed from May 1989 through December 1997. She was elected Controller of Energen in January 1998 and elected Vice President and Controller of Energen in October 2001.

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PART II

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

Quarterly Market Prices and Dividends Paid Per Share

Quarter ended (*in dollars*)	**High**	**Low**	**Close**	**Dividends Paid**
March 31, 2006	39.49	32.71	35.00	.11
June 30, 2006	38.42	32.16	38.41	.11
September 30, 2006	44.48	36.95	41.87	.11
December 31, 2006	47.60	38.50	46.94	.11
March 31, 2007	51.43	43.78	50.89	.115
June 30, 2007	60.49	51.05	54.94	.115
September 30, 2007	58.90	48.24	57.12	.115
December 31, 2007	70.41	56.81	64.23	.115

Energen s common stock is listed on the New York Stock Exchange under the symbol EGN. On February 8, 2008, there were 7,135 holders of record of Energen s common stock. At the date of this filing, Energen Corporation owned all the issued and outstanding common stock of Alabama Gas Corporation. Energen expects to pay annual cash dividends of $0.48 per share on the Company s common stock in 2008. The amount and timing of all dividend payments is subject to the discretion of the Board of Directors and is based upon business conditions, results of operations, financial conditions and other factors.

The following table summarizes information concerning securities authorized for issuance under equity compensation plans:

Plan Category	Number of Securities to be Issued for Outstanding Options and Performance Share Awards	Weighted Average Exercise Price	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans
Equity compensation plans approved by security holders*	466,339	$30.79	1,953,996
Equity compensation plans not approved by security holders	-	-	-
Total	466,339	$30.79	1,953,996

* These plans include the Company s 1997 Stock Incentive Plan and the 1992 Energen Corporation Directors Stock Plan

The following table summarizes information concerning purchases of equity securities by the issuer:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans	Maximum Number of Shares that May Yet Be Purchased Under the Plans**
October 1, 2007 through October 31, 2007	-	-	-	8,992,700
November 1, 2007 through November 30, 2007	-	-	-	8,992,700

December 1, 2007 through December 31, 2007	1,857*	$ 64.43	-	8,992,700
Total	1,857	$ 64.43	-	8,992,700

* Acquired in connection with tax withholdings and payment of exercise price on stock compensation plans.

** By resolution adopted May 24, 1994, and supplemented by a resolution adopted April 26, 2000 and June 24, 2006, the Board of Directors authorized the Company to repurchase up to 12,564,400 shares of the Company s common stock. The resolutions do not have an expiration date.

PERFORMANCE GRAPH

Energen Corporation Comparison of Five-Year Cumulative Shareholder Returns

This graph compares the total shareholder returns of Energen, the Standard & Poor s Composite Stock Index (S&P 500), the Standard & Poor s Supercomposite Oil & Gas Exploration & Production Index (S15OILP), and the Standard & Poor s Supercomposite Gas Utilities Index (S15GASUX). The graph assumes $100 invested at the per-share closing price of the common stock on the New York Exchange Composite Tape on December 31, 2002, in the Company and each of the indices. Total shareholder return includes reinvested dividends.

As of December 31,	2002	2003	2004	2005	2006	**2007**
S&P 500 Index	$ 100	$ 129	$ 143	$ 150	$ 173	**$ 183**
Energen	$ 100	$ 144	$ 210	$ 262	$ 343	**$ 473**
S15OILP Index	$ 100	$ 127	$ 172	$ 279	$ 289	**$ 413**
S15GASUX	$ 100	$ 124	$ 145	$ 157	$ 196	**$ 223**

ITEM 6. SELECTED FINANCIAL DATA

The selected financial data as set forth below should be read in conjunction with the Consolidated Financial Statements and the Notes to Financial Statements included in this Form 10-K.

SELECTED FINANCIAL AND COMMON STOCK DATA

Energen Corporation

Years ended December 31,

(dollars in thousands, except per share amounts)	**2007**	2006	2005	2004	2003
INCOME STATEMENT					
Operating revenues	**$ 1,435,060**	$ 1,393,986*	$ 1,128,394	$ 936,857	$ 841,631
Income from continuing operations	**$ 309,212**	$ 273,523*	$ 172,886	$ 127,305	$ 110,104
Net income	**$ 309,233**	$ 273,570*	$ 173,012	$ 127,463	$ 110,654
Diluted earnings per average common share from continuing operations	**$ 4.28**	$ 3.73*	$ 2.35	$ 1.74	$ 1.54
Diluted earnings per average common share	**$ 4.28**	$ 3.73*	$ 2.35	$ 1.74	$ 1.55
BALANCE SHEET					
Total property, plant and equipment, net	**$ 2,538,243**	$ 2,252,414	$ 2,068,011	$ 1,783,059	$ 1,433,451
Total assets	**$ 3,079,653**	$ 2,836,887	$ 2,618,226	$ 2,181,739	$ 1,778,232
Long-term debt	**$ 562,365**	$ 582,490	$ 683,236	$ 612,891	$ 552,842

Total shareholders equity	**$ 1,378,658**	$ 1,202,069	$ 892,678	$ 803,666	$ 699,032
COMMON STOCK DATA					
Annual dividend rate at period-end	**$ 0.46**	$ 0.44	$ 0.40	$ 0.385	$ 0.37
Cash dividends paid per common share	**$ 0.46**	$ 0.44	$ 0.40	$ 0.3775	$ 0.365
Diluted average common shares outstanding (000)	**72,181**	73,278	73,715	73,117	71,434
Price range:					
High	**$ 70.41**	$ 47.60	$ 44.31	$ 30.04	$ 21.00
Low	**$ 43.78**	$ 32.16	$ 27.06	$ 19.94	$ 14.04
Close	**$ 64.23**	$ 46.94	$ 36.32	$ 29.48	$ 20.52

* *Includes an after-tax gain of $34.5 million, or $0.47 per diluted share, on the sale of a 50 percent interest in Energen Resources acreage position in Alabama shale to Chesapeake Energy Corporation.*

All information has been restated to reflect a 2-for-1 stock split effective June 1, 2005.

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SELECTED BUSINESS SEGMENT DATA

Energen Corporation

Years ended December 31,

(dollars in thousands)	**2007**	2006	2005	2004	2003
OIL AND GAS OPERATIONS					
Operating revenues from continuing operations					
Natural gas	**$ 499,406**	$ 437,560	$ 365,635	$ 276,482	$ 235,022
Oil	**251,497**	181,459	116,651	98,409	87,192
Natural gas liquids	**68,623**	50,258	38,455	30,902	25,938
Other	**6,066**	61,265	6,953	4,324	4,380
Total	**$ 825,592**	$ 730,542	$ 527,694	$ 410,117	$ 352,532
Production volumes from continuing operations					
Natural gas (MMcf)	**64,300**	62,824	61,048	57,164	55,304
Oil (MBbl)	**3,879**	3,645	3,316	3,434	3,411
Natural gas liquids (MMgal)	**77.2**	76.3	70.5	68.2	66.6
Production volumes from continuing operations (MMcfe)	**98,606**	95,596	91,020	87,513	85,291
Total production volumes (MMcfe)	**98,605**	95,595	91,099	87,606	86,157
Proved reserves					
Natural gas (MMcf)	**1,115,918**	1,096,429	1,080,161	1,019,436	886,307
Oil (MBbl)	**74,625**	74,893	74,962	54,500	52,528
Natural gas liquids (MBbl)	**31,664**	29,504	31,934	34,613	27,245
Total (MMcfe)	**1,753,652**	1,722,811	1,721,537	1,554,114	1,364,945
Other data from continuing operations					
Lease operating expense (LOE)					
LOE and other	**$ 148,280**	$ 134,853	$ 104,241	$ 79,191	$ 67,833
Production taxes	**53,798**	49,509	52,271	37,285	27,686
Total	**$ 202,078**	$ 184,362	$ 156,512	$ 116,476	$ 95,519
Depreciation, depletion and amortization	**$ 114,241**	$ 97,842	$ 89,340	$ 80,896	$ 79,495
Capital expenditures	**$ 379,479**	$ 259,678	$ 353,712	$ 403,936	$ 163,338
Operating income	**$ 451,567**	$ 405,149	$ 243,876	$ 180,379	$ 153,325
NATURAL GAS DISTRIBUTION					
Operating revenues					
Residential	**$ 388,291**	$ 426,066	$ 384,753	$ 340,229	$ 320,938
Commercial and industrial	**164,903**	181,900	166,957	138,686	126,638
Transportation	**49,255**	45,950	43,291	40,221	38,250

Other	**7,019**	9,528	5,699	7,604	3,273
Total	**$ 609,468**	$ 663,444	$ 600,700	$ 526,740	$ 489,099
Gas delivery volumes (MMcf)					
Residential	**20,665**	22,310	24,601	25,383	27,248
Commercial and industrial	**10,593**	11,226	12,498	12,323	12,564
Transportation	**51,448**	50,760	49,850	54,385	55,623
Total	**82,706**	84,296	86,949	92,091	95,435
Average number of customers					
Residential	**416,967**	420,558	425,110	425,673	427,413
Commercial, industrial and transportation	**34,200**	34,456	34,936	35,248	35,463
Total	**451,167**	455,014	460,046	460,921	462,876
Other data					
Depreciation and amortization	**$ 47,136**	$ 44,244	$ 42,351	$ 39,881	$ 37,171
Capital expenditures	**$ 58,862**	$ 76,157	$ 73,276	$ 58,208	$ 57,906
Operating income	**$ 72,742**	$ 74,274	$ 72,922	$ 66,199	$ 66,848

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

Consolidated Net Income

Energen Corporation s net income for the year ended December 31, 2007 totaled $309.2 million, or $4.28 per diluted share and compared favorably to the year ended December 31, 2006 net income of $273.6 million, or $3.73 per diluted share. This 14.7 percent increase in earnings per diluted share (EPS) largely reflected the result of significantly higher prices for natural gas, oil and natural gas liquids and the impact of a 3 billion cubic feet equivalent (Bcfe) increase in production volumes from Energen Resources Corporation, Energen s oil and gas subsidiary, partially offset by the prior year after-tax gain of approximately $34.5 million, or $0.47 per diluted share, on the sale of a 50 percent interest in Energen Resources acreage position in Alabama shale to Chesapeake Energy Corporation (Chesapeake). For the year ended December 31, 2007, Energen Resources earned $273.2 million, as compared with $237.6 million in the previous year. Alabama Gas Corporation (Alagasco), Energen s utility subsidiary, generated net income of $36.8 million in the current year as compared with net income in the prior period of $37.3 million. For the year ended December 31, 2005, Energen reported earnings of $173 million, or $2.35 per diluted share.

2007 vs 2006: For the year ended December 31, 2007, Energen Resources net income and income from continuing operations totaled $273.2 million and compared favorably to $237.6 million in the prior year. The primary factors positively influencing income from continuing operations included higher commodity prices of approximately $80 million after-tax, the impact of increased production volumes of approximately $14 million after-tax and the Section 199 Domestic Production Activities Deduction tax benefit on qualified oil and gas production income of approximately $7 million. Negatively affecting comparable income from continuing operations was the $34.5 million after-tax gain on the acreage position sale to Chesapeake recorded in the prior year, higher depreciation, depletion and amortization (DD&A) expense of approximately $10 million after-tax, higher lease operating expense of approximately $8 million after-tax, increased administrative expenses of approximately $3 million after-tax and a prior year $6.7 million after-tax gain on the sale of Energen Resources bankruptcy claim against Enron.

Alagasco earned net income of $36.8 million in 2007 as compared with net income of $37.3 million in 2006. This decrease in earnings largely reflected revenue reductions under the utility s rate-setting mechanism of $2.3 million after-tax partially offset by a $1.2 million after-tax increase arising from the utility s ability to earn on a higher level of equity and a $0.9 million after-tax reduction in expenses associated with the prior year s Cost Control Measurement (CCM) giveback. Alagasco s return on average equity (ROE) was 12.3 percent in 2007 compared with 13.1 percent in 2006.

2006 vs 2005: Energen Resources net income rose 75.6 percent to $237.6 million in 2006. Energen Resources income from continuing operations totaled $237.6 million in 2006 as compared with $135.2 million in 2005 primarily due to increased commodity prices of approximately $77 million after-tax along with the impact of increased production volumes of approximately $16 million after-tax, the $34.5 million after-tax gain on the sale to Chesapeake and the $6.7 million after-tax gain on the Enron bankruptcy settlement. These increases were partially offset by higher lease operating expense of approximately $19 million after-tax, increased DD&A expense of approximately $5 million after-tax and increased administrative expenses of approximately $5 million after-tax. Alagasco earnings increased to $37.3 million in 2006 from $37 million in 2005 largely as a result of $2 million after-tax increase arising from the utility s ability to earn on a higher level of equity and reductions in the prior year under the utility s rate setting mechanism of $1.9 million after-tax largely offset by a decrease in customer usage and a $0.9 million after-tax reduction associated with the CCM giveback. Alagasco achieved a ROE of 13.1 percent in 2006 compared with 13.5 percent in 2005.

Operating Income

Consolidated operating income in 2007, 2006 and 2005 totaled $522 million, $477.3 million and $315.7 million, respectively. This growth in operating income has been influenced by strong financial performance from Energen Resources under Energen s diversified growth strategy. Alagasco s operating income has been relatively flat for the three previous years as the utility s ability to earn a return on a higher level of equity was offset by decreased customer usage and revenue reductions under its rate-setting mechanisms.

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Oil and Gas Operations: Revenues from oil and gas operations rose in the current year largely as a result of increased commodity prices as well as the impact of increased production volumes. Production increased primarily due to additional development activities in the San Juan and Permian basins partially offset by normal production declines. Revenue per unit of production for natural gas production increased 11.6 percent to $7.77 per thousand cubic feet (Mcf), oil revenue per unit of production rose 30.2 percent to $64.83 per barrel and natural gas liquids revenue per unit of production increased 34.8 percent to an average price of $0.89 per gallon during 2007. Production from continuing operations rose 3.1 percent to 98.6 Bcfe during 2007. Natural gas production increased 2.3 percent to 64.3 billion cubic feet (Bcf) and oil volumes increased 6.4 percent to 3,879 thousand barrels (MBbl). Production of natural gas liquids increased 1.2 percent to 77.2 million gallons (MMgal).

In 2006, revenues from oil and gas operations increased primarily as a result of increased commodity prices and increased production volumes. Production increased primarily due to additional development activities in the San Juan Basin, accelerated workovers due to milder winter weather and increased volumes related to the purchase of Permian Basin oil properties in the fourth quarter of 2005. Negatively affecting production were normal production declines. Revenue per unit of production related to natural gas increased 16.2 percent to $6.96 per Mcf, oil revenue per unit of production rose 41.5 percent to $49.79 per barrel and natural gas liquids revenue per unit of production increased 20 percent to an average price of $0.66 per gallon during the year ended December 31, 2006. Production from continuing operations increased 5 percent to 95.6 Bcfe in 2006. Natural gas production rose 2.9 percent to 62.8 Bcf, oil volumes increased 9.9 percent to 3,645 MBbl and natural gas liquids production increased 8.2 percent to 76.3 MMgal.

Coalbed methane operating fees are calculated as a percentage of net proceeds on certain properties, as defined by the related operating agreements, and vary with changes in natural gas prices, production volumes and operating expenses. Revenues from operating fees were $6.1 million, $6.6 million and $8.7 million in 2007, 2006 and 2005, respectively. During 2006, Energen Resources recorded a $55.5 million pre-tax gain in other operating revenues for the sale of a 50 percent interest in Energen Resources acreage position in Alabama shale to Chesapeake.

Years ended December 31, (in thousands, except sales price data)	**2007**	2006	2005
Operating revenues from continuing operations			
Natural gas	**$ 499,406**	$ 437,560	$ 365,635
Oil	**251,497**	181,459	116,651
Natural gas liquids	**68,623**	50,258	38,455
Operating fees	**6,119**	6,553	8,674
Other	**(53)**	54,712	(1,721)
Total operating revenues from continuing operations	**$ 825,592**	$ 730,542	$ 527,694
Production volumes from continuing operations			
Natural gas (MMcf)	**64,300**	62,824	61,048
Oil (MBbl)	**3,879**	3,645	3,316
Natural gas liquids (MMgal)	**77.2**	76.3	70.5
Revenue per unit of production including effects of all derivative instruments			
Natural gas (per Mcf)	**$ 7.77**	$ 6.96	$ 5.99
Oil (per barrel)	**$ 64.83**	$ 49.79	$ 35.18
Natural gas liquids (per gallon)	**$ 0.89**	$ 0.66	$ 0.55
Revenue per unit of production including effects of qualifying cash flow hedges			
Natural gas (per Mcf)	**$ 7.76**	$ 6.96	$ 6.36
Oil (per barrel)	**$ 64.80**	$ 49.54	$ 35.18
Natural gas liquids (per gallon)	**$ 0.89**	$ 0.66	$ 0.55
Revenue per unit of production excluding effects of all derivative instruments			
Natural gas (per Mcf)	**$ 6.45**	$ 6.53	$ 7.81
Oil (per barrel)	**$ 67.17**	$ 59.88	$ 51.61
Natural gas liquids (per gallon)	**$ 0.98**	$ 0.80	$ 0.74
Average production (lifting) cost (per Mcfe)	**$ 1.50**	$ 1.41	$ 1.15

Average production tax (per Mcfe)	**$**	**0.55**	$	0.52	$	0.57
Average DD&A rate (per Mcfe)	**$**	**1.13**	$	1.00	$	0.96

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Operations and maintenance (O&M) expense increased $28.7 million and $31.5 million in 2007 and 2006, respectively. Lease operating expense (excluding production taxes) in 2007 increased $13.4 million largely due to additional compression costs (approximately $2 million), increased repair and maintenance expense in the San Juan and Permian basins (approximately $7 million), higher transportation related to increased San Juan Basin production (approximately $3 million) and a general rise in field service costs. In 2006, lease operating expense (excluding production taxes) increased by $30.6 million due to a variety of factors including the December 2005 acquisition of Permian Basin oil properties (approximately $9 million), additional maintenance expense primarily in the San Juan Basin designed to increase production (approximately $2 million), increased workover expense (approximately $6 million), higher transportation costs (approximately $4 million), an increased number of wells in period comparisons and other overall cost increases. In 2007, administrative expense increased $16.6 million primarily due to a prior year pre-tax gain of $10.7 million on the sale of Energen Resources bankruptcy claims against Enron and increased labor-related costs, including settlement charges for the nonqualified supplemental retirement plans and the defined benefit pension plans of $2.3 million. Administrative expense decreased $2.6 million in 2006 largely due to the $10.7 million pre-tax gain against Enron; this gain was partially offset by higher labor-related costs. Exploration expense declined $1.3 million in 2007 largely due to decreased exploratory efforts. In 2006, exploration expense rose $3.5 million.

DD&A expense increased $16.4 million in 2007 and $8.5 million in 2006. The average DD&A rates were $1.13 per Mcfe in 2007, $1.00 per Mcfe in 2006 and $0.96 per Mcfe in 2005. The increase in the average 2007 DD&A rate, which contributed approximately $13 million, was primarily due to higher development costs along with a decline in prior year-end reserve prices. Increased production volumes also contributed approximately $3 million to the increase in DD&A expense in the current year. The increase in the average 2006 rate contributed approximately $3.8 million and was largely due to higher depletion rates on oil properties purchased in the Permian Basin in December 2005 and higher rates due to a downward revision to estimated reserves resulting from a reduction in year-end reserve prices. Partially offsetting the higher rate was increased production in lower rate areas. Increased production volumes contributed approximately $4.4 million due to the 2006 increase in DD&A expense.

Energen Resources expense for taxes other than income taxes primarily reflected production-related taxes. Energen Resources recorded severance taxes of $53.8 million, $49.5 million and $52.3 million for 2007, 2006 and 2005, respectively. Severance taxes increased $4.3 million in 2007 over the prior year. Higher commodity market prices and the impact of increased production volumes contributed approximately $3 million and $1.6 million, respectively. Decreased severance taxes in 2006 resulted from lower natural gas commodity market prices largely offset by higher production volumes and increased oil and natural gas liquids commodity market prices. Commodity market prices exclude the effects of derivative instruments for purposes of determining severance taxes.

Natural Gas Distribution: As discussed more fully in Note 2, Regulatory Matters, in the Notes to Financial Statements, Alagasco is subject to regulation by the Alabama Public Service Commission (APSC). On December 21, 2007, the APSC issued an order to extend the utility s rate-setting mechanism. Under the terms of the extension, RSE will continue after December 31, 2014, unless, after notice to the company and a hearing, the APSC votes to modify or discontinue the RSE methodology. Alagasco s allowed range of return on equity remains 13.15 percent to 13.65 percent throughout the term of the order. Prior to the December 21, 2007 extension, RSE limited the utility s equity upon which a return is permitted to 60 percent of total capitalization and provided for certain cost control measures designed to monitor Alagasco s O&M expense. Subsequent to the extension, the equity on which a return will be permitted will be phased down to 57 percent by December 31, 2008 and 55 percent by December 31, 2009.

Prior to the extension, under the inflation-based CCM established by the APSC, if the percentage change in O&M expense per customer fell within a range of 1.25 points above or below the percentage change in the Consumer Price Index For All Urban Consumers (index range), no adjustment was required. If the change in O&M expense per customer exceeded the index range, three-quarters of the difference was returned to customers. To the extent the change was less than the index range, the utility benefited by one-half of the difference through future rate adjustments. The changes to the O&M expense cost control measurement subsequent to the extension are as follows: annual changes in O&M expense will be measured on an aggregate basis rather than per customer; the

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percentage change in O&M expense must fall within a range of 0.75 points above or below the percentage change in the index range; certain items that fluctuate based on situations demonstrated to be beyond Alagasco s control may be excluded for the cost control measurement calculation; the O&M expense base for measurement purposes will continue to be set at the prior year s actual O&M expense amount unless the Company exceeds the top of the index range in two successive years, in which case the base for the following year will be set at the top of the index range.

Alagasco generates revenues through the sale and transportation of natural gas. The transportation rate does not contain an amount representing the cost of gas, and Alagasco s rate structure allows similar margins on transportation and sales gas. Weather can cause variations in space heating revenues, but the financial impact is moderated by a temperature adjustment mechanism that requires Alagasco to adjust certain customer bills monthly to reflect changes in usage due to departures from normal temperatures. The temperature adjustment applies primarily to residential, small commercial and small industrial customers.

Alagasco s natural gas and transportation sales revenues totaled $609.5 million, $663.4 million and $600.7 million in 2007, 2006 and 2005, respectively. Sales revenue in 2007 declined largely due to a decrease in gas costs of approximately $28 million and a decline in customer usage of approximately $27 million. In 2006, sales revenue increased primarily due to an increase in gas costs approximately $82 million partially offset by a decrease in customer usage of approximately $28 million. In 2007, weather was 7.9 percent warmer than in the prior year. Residential sales volumes declined 7.4 percent while commercial and industrial volumes decreased 5.6 percent. Transportation volumes rose 1.4 percent. In 2006, weather that was 2.5 percent warmer than in the prior year along with customer conservation related to higher gas costs contributed to a 9.3 percent decline in residential sales volumes while commercial and industrial volumes decreased 10.2 percent. Transportation volumes increased 1.8 percent. In 2007, lower gas costs along with decreased gas purchase volumes contributed to a 14.7 percent decrease in cost of gas. Higher gas costs partially offset by a decline in gas purchase volumes resulted in a 17.2 percent increase in cost of gas in 2006.

O&M expense at the utility increased 1.9 percent in 2007 primarily due to increased labor-related costs (approximately $2 million), including settlement charges for the nonqualified supplemental retirement plans and the defined benefit pension plans of $3.4 million, largely offset by decreased bad debt expense (approximately $1 million). In 2006, O&M expense increased slightly primarily due to higher bad debt expense (approximately $1 million) and increased distribution maintenance expenses (approximately $1.7 million). These increases were offset by decreased labor-related expenses (approximately $4.5 million). The increase in O&M expense per customer for the rate year ended September 30, 2006 was above the inflation-based CCM established by the APSC as part of the utility s rate-setting mechanism; as a result, three quarters of the differences, or $1.5 million pre-tax, was returned to the customers through RSE (see Note 2, Regulatory Matters, in the Notes to Financial Statements). Alagasco s O&M expense fell within the index range for the rate years ended September 30, 2007 and 2005.

Depreciation expense rose 6.5 percent and 4.5 percent in 2007 and 2006, respectively, due to extension and replacement of the utility s distribution and replacement of its support systems. Alagasco s expense for taxes other than income primarily reflects various state and local business taxes as well as payroll-related taxes. State and local business taxes generally are based on gross receipts and fluctuate accordingly.

Years ended December 31, (in thousands)	**2007**	2006	2005
Natural gas transportation and sales revenues	**$ 609,468**	$ 663,444	$ 600,700
Cost of natural gas	**(318,429)**	(373,097)	(318,269)
Operations and maintenance	**(129,351)**	(126,948)	(126,041)
Depreciation	**(47,136)**	(44,244)	(42,351)
Income taxes	**(21,636)**	(22,002)	(22,360)
Taxes, other than income taxes	**(41,810)**	(44,881)	(41,117)
Operating income	**$ 51,106**	$ 52,272	$ 50,562
Natural gas sales volumes (MMcf)			
Residential	**20,665**	22,310	24,601
Commercial and industrial	**10,593**	11,226	12,498
Total natural gas sales volumes	**31,258**	33,536	37,099
Natural gas transportation volumes (MMcf)	**51,448**	50,760	49,850
Total deliveries (MMcf)	**82,706**	84,296	86,949

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Non-Operating Items

Consolidated: Interest expense in 2007 declined $1.6 million primarily due to lower borrowings at Energen Resources along with decreased interest expense associated with the May 2007 voluntary call of the $100 million Floating Rate Senior Notes due November 15, 2007. Also contributing to the decrease in interest expense at Alagasco was the January 2007 redemption of $34.4 million of 6.75% Notes maturing September 1, 2031 and $10 million of 7.97% Medium-Term Notes maturing September 23, 2026 partially offset by the issuance of $45 million in long-term debt with an interest rate of 5.9%. Interest expense in 2006 increased $1.9 million largely due to financing costs associated with higher storage gas inventories at Alagasco and an increase in interest rates associated with Energen s $100 million Floating Rate Senior Notes. The average daily outstanding balance under short-term credit facilities was $67.7 million in 2007. The average daily outstanding balance under short-term credit facilities was $63.7 million in 2006 as compared to $17.7 million in 2005. Income tax expense increased in the periods presented primarily due to higher pre-tax income. Partially offsetting the increase in income tax expense in 2007 was the after-tax impact of the Section 199 deduction (approximately $7 million after-tax).

FINANCIAL POSITION AND LIQUIDITY

The Company s net cash from operating activities totaled $484.2 million, $482.9 million and $335.1 million in 2007, 2006 and 2005, respectively. Operating cash flow in 2007, 2006 and 2005 benefited from higher realized commodity prices and production volumes at Energen Resources. Negatively affecting operating cash flows during 2007 was an increase in income taxes payable related to depreciation and basis differences in the current period and the prior period utilization of minimum tax credit. In 2006, income from operations before income taxes included a pre-tax gain of $55.5 million related to the Chesapeake acreage sale; the cash proceeds from the sale are included in the investing activities on the Consolidated Statements of Cash Flows, as described more fully below. Working capital needs at Alagasco were reduced by declining gas costs for 2007. During 2006 and 2005, working capital needs at Alagasco were largely affected by increased gas costs compared to the prior period and storage gas inventory. Other working capital items, which primarily are the result of changes in throughput and the timing of payments, combined to create the remaining increases for all years.

During 2007, the Company made net investments of $431.9 million. Energen Resources invested $54.6 million in property acquisitions, including an $18 million acquisition in the Permian Basin and approximately $32 million of unproved leaseholds (including approximately $28 million related to Alabama shale), $313.2 million for development costs including approximately $202 million to drill 345 gross development wells and $7.5 million for exploration. Utility expenditures in 2007 totaled $58.2 million and primarily represented extension and replacement of its distribution system and support facilities. During 2006, the Company made net investments of $256.9 million. Energen Resources invested $46.4 million in property acquisitions, $186.3 million for development costs including approximately $130.6 million to drill 309 gross development wells and $25.9 million for exploration. In December 2006, Energen Resources completed its purchase of gas properties located in the San Juan Basin from Dominion Resources, Inc. for approximately $30 million. Energen Resources sold certain properties during 2006, resulting in cash proceeds of $79.4 million including $75 million received from Chesapeake for a 50 percent interest in its lease position in certain unproved shale acreage in Alabama. Utility expenditures in 2006 totaled $75.1 million. During 2005, cash used in investing activities totaled $400.7 million. Energen Resources invested $188.4 million in property acquisitions, $157.5 million for development costs including approximately $123 million to drill 294 gross development wells and $5.1 million for exploration. In December 2005, Energen Resources completed its purchase of oil properties located in the Permian Basin for approximately $168 million. During 2005, Energen Resources sold certain properties resulting in cash proceeds of $10.8 million. Utility expenditures in 2005 totaled $72.4 million.

During 2007, the Company added approximately 15 Bcfe of reserves primarily from the Permian Basin acquisition. Also during 2007, Energen Resources added 127 Bcfe of reserves from discoveries and other additions, primarily the result of improved drilling technology that increased the number of proved undeveloped locations in the San Juan Basin as well as continued downspacing in the Permian Basin**.** Energen Resources added approximately 167 Bcfe and 224 Bcfe of reserves in 2006 and 2005, respectively.

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The Company used $53.9 million for net financing activities in 2007 primarily for the early redemption of $100 million Floating Rate Senior Notes due November 15, 2007, $34.4 million of 6.75% Notes maturing September 1, 2031, $10 million of Medium-Term Notes, Series A, with an annual interest rate of 8.09% due September 15, 2026 and $10 million of 7.97% Medium-Term Notes maturing September 23, 2026. Partially offsetting these uses of cash was the January 2007 issuance by Alagasco of $45 million in long-term debt with an interest rate of 5.9% due January 15, 2037. In 2006, net cash used for financing activities totaled $224.4 million largely due to $84.3 million incurred from the buy-back of Energen common stock under its stock repurchase plan along with the repayment of short-term borrowings. In addition, long-term debt was reduced by $15.9 million for current maturities in 2006. The Company provided $69.8 million from net financing activities in 2005. In January 2005, Alagasco issued $40 million of long-term debt with an interest rate of 5.2 percent due January 15, 2020 and $40 million of long-term debt with an interest rate of 5.7 percent due January 15, 2035. In November 2005, Alagasco issued $80 million of long-term debt with an interest rate of 5.368 percent due December 1, 2015. Long-term debt was reduced by $84.8 million including Alagasco s redemption of $18 million in Medium-Term Notes maturing June 27, 2007 to July 5, 2022 in August 2005 and $56.7 million of long-term debt maturing June 15, 2015 to June 27, 2025 in December 2005. For each of the years, net cash used in financing activities also reflected dividends paid to common stockholders.

Capital Expenditures

Oil and Gas Operations: Energen Resources spent a total of approximately $1 billion for capital projects during the years ended December 31, 2007, 2006 and 2005. Property acquisition expenditures totaled $289.5 million, development activities totaled $656.9 million, and exploratory expenditures totaled $38.5 million.

Years ended December 31, (in thousands)	**2007**	2006	2005
Capital and exploration expenditures for:			
Property acquisitions	**$ 54,626**	$ 46,428	$ 188,403
Development	**313,220**	186,264	157,458
Exploration	**7,456**	25,936	5,065
Other	**5,667**	4,411	3,037
Total	**380,969**	263,039	353,963
Less exploration expenditures charged to income	**1,490**	3,361	251
Net capital expenditures	**$ 379,479**	$ 259,678	$ 353,712

Natural Gas Distribution: During the years ended December 31, 2007, 2006 and 2005, Alagasco invested $208.3 million for capital projects: $164.5 million for expansion, replacements and support of its distribution system and $43.7 million for support facilities and the development and implementation of information systems.

Years ended December 31, (in thousands)	**2007**	2006	2005
Capital expenditures for:			
Renewals, replacements, system expansion and other	**$ 50,924**	$ 60,244	$ 53,381
Support facilities	**7,938**	15,913	19,895
Total	**$ 58,862**	$ 76,157	$ 73,276

FUTURE CAPITAL RESOURCES AND LIQUIDITY

The Company plans to continue investing significant capital in Energen Resources s oil and gas production operations. For 2008, the Company expects its oil and gas capital spending to total approximately $308 million, including $290 million for existing properties. Included in this $290 million is approximately $153 million for the development of previously identified proved undeveloped reserves. The Company expects capital spending to total approximately $271 million during 2009, including approximately $260 million for existing properties. Included in this $260 million is approximately $81 million for the development of previously identified proved undeveloped reserves.

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Capital expenditures by area during 2008 are planned as follows:

Year ended December 31, (in thousands)	2008
San Juan Basin	$ 92,300
Permian Basin	162,150
Black Warrior Basin	10,500
North Louisiana/East Texas	25,300
Other	17,350
Total	$ 307,600

As of December 31, 2007, Energen Resources had approximately $28 million of unproved leaseholds costs related to its lease position in Alabama shale. As of February 25, 2008, Energen Resources net acreage position in Alabama shale totaled approximately 287,500 acres and represents multiple shale opportunities. In 2008, the Company will begin a 5 to 10 well test program. The Company has not included in its capital spending estimates discussed above any amounts associated with exploratory drilling and/or future potential development for the Alabama shale position.

Energen anticipates having the following drilling rigs and net wells by area during 2008. The drilling rigs presented below are operated while the net wells include operated and non-operated wells.

	Drilling Rigs	Net Wells
San Juan Basin	6	67

Permian Basin	4 - 5	209
Black Warrior Basin	1-2	31
North Louisiana/East Texas	2	10
Total	13 - 15	317

The Company also may allocate additional capital for other oil and gas activities such as property acquisitions, additional accelerated development of existing properties and the exploration and further development of potential shale acreage primarily in Alabama. Energen Resources may evaluate acquisition opportunities which arise in the marketplace and from time to time will pursue acquisitions that meet Energen s acquisition criteria. Energen Resources ability to invest in property acquisitions is subject to market conditions and industry trends. Property acquisitions are not included in the aforementioned estimate of oil and gas investments and could result in capital expenditures different from those outlined above.

To finance capital spending at Energen Resources, the Company primarily expects to use internally generated cash flow supplemented by its short-term credit facilities. The Company also may issue long-term debt and equity periodically to replace short-term obligations, enhance liquidity and provide for permanent financing.

Energen also plans to consider stock repurchases as a capital investment. In May 2006, Energen began a buy-back of its common stock under an existing stock repurchase plan. In June 2006, the Company s Board of Directors authorized an additional 9 million shares of common stock for repurchase. Energen may buy shares from time to time on the open market or in negotiated purchases. The timing and amounts of any repurchases are subject to changes in market conditions. During 2006, the Company purchased 2.2 million shares at an average price of $39.08 per share. The Company did not repurchase shares of common stock for this program during 2007. The Company plans to continue utilizing internally generated cash flow to fund any future stock repurchases. During 2008, the Company anticipates purchasing approximately $27 million of Company common stock in conjunction with tax withholdings on its non-qualified deferred compensation plan and other stock compensation. The Company plans to utilize internally generated cash flows to fund these purchases of common stock.

Energen Resources has experienced various market driven conditions generally caused by the increased commodity price environment including, but not limited to, increased finding and development costs, higher workover and maintenance expenses, increased taxes and other field-service-related expenses. The Company anticipates influences such as weather, natural disasters, changes in global economics and political unrest will continue to contribute to increased commodity price volatility in the near term. Commodity price volatility will affect the Company s revenue and associated cash flow available for investment.

Alagasco s use of commodity price hedges for a portion of its gas supply needs is reflected in the utility s current rates. Alagasco s rate schedules for natural gas distribution charges contain a Gas Supply Adjustment (GSA) rider which permits the pass-through to customers for changes in the cost of gas supply. The GSA rider is designed to capture the Company s cost of natural gas and provides for a pass-through of gas cost fluctuations to customers without markup; the cost of gas includes the commodity cost, pipeline capacity, transportation and fuel costs, and risk management gains and losses. Sustained higher natural gas prices may decrease Alagasco s customer base and could result in a further decline of per customer use and number of customers. The utility will continue to monitor its bad debt reserve and will make adjustments as required based on the evaluation of its receivables which are impacted by natural gas prices.

Alagasco maintains an investment in storage gas that is expected to average approximately $65 million in 2008 but may vary depending upon the price of natural gas. During 2008 and 2009, Alagasco plans to invest approximately $69 million and $79 million, respectively, in utility capital expenditures for normal distribution and support systems. The utility anticipates funding these capital requirements through internally generated cash flow and the utilization of short-term credit facilities. Alagasco issued $45 million in long-term debt with an interest rate of 5.9% in January 2007 and redeemed $34.4 million of 6.75% Notes maturing September 1, 2031 and $10 million of 7.97% Medium-Term Notes maturing September 23, 2026 in the same period in order to capitalize on lower interest rates.

Access to capital is an integral part of the Company s business plan. The Company regularly provides information to corporate rating agencies related to current business activities and future performance expectations. On September 25, 2007, Moody s Investors Service (Moody s) downgraded the debt rating of Energen to Baa3 senior unsecured from Baa2. Energen s debt rating of Baa3 remains investment grade and reflects Moody s assignment of increased exposure to the Company related to the growth of its oil and gas operations. Moody s also confirmed the debt rating of Alagasco during this review as A1 senior unsecured. On October 31, 2007, Standard & Poor s affirmed its BBB+ corporate credit rating on Energen and Alagasco; the outlook remained stable. While the Company expects to have ongoing access to its short-term credit facilities and the broader long-term markets, continued access could be adversely affected by future economic and business conditions and credit rating downgrades. To help finance its growth plans and operating needs, the Company currently has available short-term credit facilities aggregating $415 million of which Energen has available $255 million, Alagasco has available $110 million and $50 million is available to either Company. At December 31, 2007, Energen and Alagasco had borrowings of $72 million and $62 million, respectively on its short-term credit facilities.

Dividends

Energen expects to pay annual cash dividends of $0.48 per share on the Company s common stock in 2008. The amount and timing of all dividend payments is subject to the discretion of the Board of Directors and is based upon business conditions, results of operations, financial conditions and other factors.

On April 27, 2005, Energen s shareholders approved a 2-for-1 split of the Company s common stock. The split was effected in the form of a 100 percent stock dividend and was effective on June 1, 2005, to shareholders of record on May 13, 2005. All share and per share amounts of capital stock outstanding have been adjusted to reflect the stock split.

Contractual Cash Obligations and Other Commitments

In the course of ordinary business activities, Energen enters into a variety of contractual cash obligations and other commitments. The following table summarizes the Company s significant contractual cash obligations, other than hedging contracts, as of December 31, 2007.

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	Payments Due before December 31,				
(in thousands)	**Total**	**2008**	**2009-2010**	**2011-2012**	**2013 and Thereafter**
Short-term debt	$ 134,000	$ 134,000	$ -	$ -	$ -
Long-term debt [(1)]	573,467	10,000	150,000	6,000	407,467
Interest payments on debt	446,010	37,300	72,945	50,050	285,715
Purchase obligations [(2)]	178,400	50,964	89,450	17,751	20,235
Capital lease obligations	-	-	-	-	-
Operating leases	46,147	4,128	8,092	7,339	26,588
Asset retirement obligations [(3)]	491,444	5,069	7,311	2,106	476,958
Nonqualified supplemental retirement plans	35,111	3,126	4,811	4,711	22,463
Total contractual cash obligations	$ 1,904,579	$ 244,587	$ 332,609	$ 87,957	$ 1,239,426

(1) Long-term cash obligations include $1.1 million of unamortized debt discounts as of December 31, 2007.

(2) Certain of the Company s long-term gas procurement contracts for the supply, storage and delivery of natural gas include fixed charges of $178 million through October 2015. The Company also is committed to purchase minimum quantities of gas at market-related prices or to pay certain costs in the event the minimum quantities are not taken. These purchase commitments are approximately 135.2 Bcf through April 2015.

(3) Represents the estimated future asset retirement obligation on an undiscounted basis.

Energen Resources operates in certain instances through joint ventures under joint operating agreements. Typically, the operator under a joint operating agreement enters into contracts, such as drilling contracts, for the benefit of all joint venture partners. Through the joint operating agreement, the non-operators reimburse, and in some cases advance, the funds necessary to meet the contractual obligations entered into by the operator. These obligations are typically shared on a working interest basis as defined in the joint operating contractual agreement.

The Company has two defined non-contributory pension plans and provides certain postretirement healthcare and life insurance benefits. The Company is not required to make any funding payments during 2008 for the pension plans and does not currently plan to make discretionary contributions. The Company expects to make discretionary payments of approximately $2.2 million to postretirement benefit program assets during 2008. The contractual obligations reported above exclude any payments the Company expects to make to postretirement benefit program assets.

The contractual obligations reported above exclude the Company s liability of $8.5 million recognized under FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes-an Interpretation of FASB Statement No. 109 (FIN 48) related to the Company s provision for uncertain tax positions. The Company cannot make a reasonably reliable estimate of the amount and period of related future payments for such liability.

OUTLOOK

Oil and Gas Operations: Energen Resources plans to continue to implement its growth strategy with capital spending in 2008 and 2009 as outlined above. Production in 2008 is estimated to be 102 Bcfe, including approximately 100 Bcfe of estimated production from proved reserves owned at December 31, 2007. In 2009, production is estimated to be 108 Bcfe, including approximately 100 Bcfe produced from proved reserves currently owned. Production estimates above do not include amounts for potential future acquisitions or Alabama shale.

Production volumes by area are expected to be as follows:

Years Ended December 31, (Bcfe)	2008	2009
San Juan Basin	50	54
Permian Basin	30	34
Black Warrior Basin	14	14
North Louisiana/East Texas	8	6
Total	102	108

During 2008 and 2009, Energen Resources expects an annualized decline rate of approximately 7 percent for its proved developed producing properties owned at December 31, 2007. During the same period, total production from proved properties is expected to increase approximately 1 percent and total production is expected to increase approximately 4 percent. Total production estimates do not include any production associated with the Alabama shale position.

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In the event Energen Resources is unable to fully invest in its capital investment opportunities, future operating revenues, production and proved reserves could be negatively affected. Energen Resources major market risk exposure is in the pricing applicable to its oil and gas production. Historically, prices received for oil and gas production have been volatile because of seasonal weather patterns, national supply and demand factors and general economic conditions. Crude oil prices also are affected by quality differentials, worldwide political developments and actions of the Organization of Petroleum Exporting Countries. Basis differentials, like the underlying commodity prices, can be volatile because of regional supply and demand factors, including seasonal variations and the availability and price of transportation to consuming areas.

Revenues and related accounts receivable from oil and gas operations primarily are generated from the sale of produced oil, natural gas and natural gas liquids to energy marketing companies. Such sales are typically made on an unsecured credit basis with payment due the month following delivery. This concentration of sales to the energy marketing industry has the potential to affect the Company s overall exposure to credit risk, either positively or negatively, in that the Company s oil and gas purchasers may be affected similarly by changes in economic, industry or other conditions. Energen Resources considers the credit quality of its customers and, in certain instances, may require credit assurances such as a deposit, letter of credit or parent guarantee. The four largest oil, natural gas and natural gas liquids purchasers account for approximately 22 percent, 14 percent, 11 percent and 10 percent, respectively, of Energen Resources estimated 2008 production. Energen Resources other purchasers each bought less than 8 percent of production.

Energen Resources periodically enters into derivative commodity instruments that qualify as cash flow hedges under SFAS No. 133 to hedge its price exposure to its estimated oil, natural gas and natural gas liquids production. Such instruments may include regulated natural gas and crude oil futures contracts traded on the New York Mercantile Exchange (NYMEX) and over-the-counter swaps, collars and basis hedges with major energy derivative product specialists. The counterparties to the commodity instruments are investment banks and energy-trading firms. In some contracts, the amount of credit allowed before Energen Resources must post collateral for out-of-the-money hedges varies depending on the credit rating of the Company. At December 31, 2007, the counterparty agreements under which the Company had active positions did not include collateral posting requirements. Energen Resources was in a net gain position with three of its counterparties and a net loss with the remaining four. The Company believes the creditworthiness of these counterparties is satisfactory. Hedge transactions are pursuant to standing authorizations by the Board of Directors, which do not permit speculative positions. Energen Resources does not hedge more than 80 percent of its estimated annual production and generally does not hedge this production more than two years forward. Production may be hedged for a longer period immediately following an acquisition in order to protect targeted returns.

Energen Resources entered into the following transactions for 2008 and subsequent years:

Production Period	**Total Hedged Volumes**	**Average Contract Price**	**Description**

Natural Gas			
2008	30.8 Bcf	$8.53 Mcf	NYMEX Swaps
2008	18.8 Bcf	$7.53 Mcf	Basin Specific Swaps
2009	24.7 Bcf	$7.81 Mcf	Basin Specific Swaps
2009	*14.2 Bcf	$8.55 Mcf	NYMEX Swaps
2009	*4.9 Bcf	$7.55 Mcf	Basin Specific Swaps
Natural Gas Basis Differential			
2008	12.0 Bcf	**	Basis Swaps
Oil			
2008	3,203 MBbl	$70.17 Bbl	NYMEX Swaps
2009	2,460 MBbl	$71.03 Bbl	NYMEX Swaps
2009	*240 MBbl	$92.38 Bbl	NYMEX Swaps
2010	720 MBbl	$81.20 Bbl	NYMEX Swaps
Oil Basis Differential			
2008	2,483 MBbl	**	Basis Swaps
2009	1,980 MBbl	**	Basis Swaps
2009	*156 MBbl	**	Basis Swaps
Natural Gas Liquids			
2008	47.8 MMGal	$0.96 Gal	Liquids Swaps
2009	20.2 MMGal	$1.05 Gal	Liquids Swaps

* Contracts entered into subsequent to December 31, 2007

** Average contract prices not meaningful due to the varying nature of each contract

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The Company has prepared a sensitivity analysis to evaluate the hypothetical effect that changes in the market value of crude oil, natural gas and natural gas liquids may have on the fair value of its derivative instruments. This analysis measured the impact on the commodity derivative instruments and, thereby, did not consider the underlying exposure related to the commodity. At December 31, 2007, the Company was in a net loss position of $110.6 million for derivative contracts and estimates that a 10 percent increase or decrease in the commodities prices would have resulted in a $116.8 million change in the fair value of open derivative contracts; however, gains and losses on derivative contracts are expected to be similarly offset by sales at the spot market price. The hypothetical change in fair value was calculated by multiplying the difference between the hypothetical price and the contractual price by the contractual volumes and did not include the impact of related taxes on actual cash prices.

Natural Gas Distribution: The extension of RSE in December 2007 provides Alagasco the opportunity to continue earning an allowed ROE between 13.15 percent and 13.65 percent through December 31, 2014. Under the terms of that extension, RSE will continue beyond that date, unless, after notice to the Company and a hearing, the APSC votes to modify or discontinue its operations. Alagasco s rate schedules for natural gas distribution charges contain a Gas Supply Adjustment rider which permits the pass-through to customers for changes in the cost of gas supply. Also as discussed in Note 2, Regulatory Matters, in the Notes to Financial Statements, the utility s CCM is based on the rate of inflation. Continued low inflation and significantly higher gas prices resulting in increased bad debt expense could impact the utility s ability to manage its O&M expense sufficiently for the inflation-based cost control requirements of RSE and may result in an average return on equity lower than the allowed range of return. In addition, continued decreases in residential customers and continued declines in use per customer in the residential and small commercial classes will make it more difficult for the utility to earn within its allowed range of return on equity. The utility continues to rely on rate flexibility to deter bypass of its distribution system by large industrial and commercial customers.

As required by SFAS No. 133, Alagasco recognizes all derivatives at fair value as either assets or liabilities on the balance sheet. Any gains or losses are passed through to customers using the mechanisms of the GSA in compliance with Alagasco s APSC-approved tariff and are recognized as a regulatory asset or regulatory liability as required by SFAS No. 71. At December 31, 2007, Alagasco recorded a $0.4 million loss as a liability in accounts payable with a corresponding current regulatory asset representing the fair value of derivatives. The gains or losses related to these derivative contracts, as adjusted for any changes in the fair value, will be recognized in the GSA during the first quarter of 2008.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The Company s consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America. Management has identified the following critical accounting policies in the application of existing accounting standards or in the implementation of new standards that involve significant judgments and estimates by the Company. The application of these accounting policies necessarily requires managements most subjective or complex judgments regarding estimates and projected outcomes of future events that could have a material impact on the financial statements.

Oil and Gas Operations

Accounting for Natural Gas and Oil Producing Activities and Related Reserves: The Company utilizes the successful efforts method of accounting for its natural gas and oil producing activities. Under this accounting method, acquisition and development costs of proved properties are capitalized and amortized on a units-of-production basis over the remaining life of total proved and proved developed reserves. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data

demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Accordingly, these estimates do not include probable or possible reserves. Estimated oil and gas reserves are based on currently available reservoir data and are subject to future revision. Estimates of physical quantities of oil and gas reserves have been determined by Company engineers. Independent oil and gas reservoir engineers have reviewed the estimates of proved reserves of natural gas, crude oil and natural gas liquids attributed to the Company s net interests in oil and gas properties as of December 31, 2007. The independent reservoir engineers have issued reports covering approximately 98 percent of the Company s ending proved reserves and in their judgment these estimates were reasonable in the aggregate. The Company s production of undeveloped reserves requires the installation or completion of related infrastructure facilities such as pipelines and the drilling of development wells.

Changes in oil and gas prices, operating costs and expected performance from the properties can result in a revision to the amount of estimated reserves held by the Company. If reserves are revised upward, earnings could be affected due to lower depreciation and depletion expense per unit of production. Likewise, if reserves are revised downward, earnings could be affected due to higher depreciation and depletion expense or due to an immediate writedown of the property s book value if an impairment is warranted. The table below reflects an estimated increase in 2008 depreciation, depletion and amortization expense associated with an assumed downward revision in the reported oil and gas reserve amounts at December 31, 2007:

	Percentage Change in Oil & Gas Reserves From Reported Reserves as of December 31, 2007	
(dollars in thousands)	-5%	-10%
Estimated increase in DD&A expense for the year ended December 31, 2008, net of tax	$ 3,900	$ 8,200

Exploratory drilling costs are capitalized pending determination of proved reserves. If proved reserves are not discovered, the exploratory drilling costs are expensed. Other exploration costs, including geological and geophysical costs, are expensed as incurred.

Asset Impairments: Oil and gas proved properties periodically are assessed for possible impairment, generally on a field-by-field basis, using the estimated undiscounted future cash flows of each field. Impairment losses are recognized when the estimated undiscounted future cash flows are less than the current net book values of the properties in a field. The Company monitors its oil and gas properties as well as the market and business environments in which it operates and makes assessments about events that could result in potential impairment issues. Such potential events may include, but are not limited to, substantial commodity price declines, unanticipated increased operating costs, and lower-than-expected production performance. If a material event occurs, Energen Resources makes an estimate of undiscounted future cash flows to determine whether the asset is impaired. If the asset is impaired, the Company will record an impairment loss for the difference between the net book value of the properties and the fair value of the properties. The fair value of the properties typically is estimated using discounted cash flows.

Cash flow and fair value estimates require Energen Resources to make projections and assumptions for pricing, demand, competition, operating costs, legal and regulatory issues, discount rates and other factors for many years into the future. These variables can, and often do, differ from the estimates and can have a positive or negative impact on the Company s need for impairment or on the amount of impairment. In addition, further changes in the economic and business environment can impact the Company s original and ongoing assessments of potential impairment.

Energen Resources adheres to Statement of Financial Accounting Standards (SFAS) No.19, Financial Accounting and Reporting by Oil and Gas Producing Companies, for recognizing any impairment of capitalized costs to unproved properties. The greatest portion of these costs generally relates to the acquisition of leasehold costs. The costs are capitalized and periodically evaluated as to recoverability, based on changes brought about by economic factors and potential shifts in business strategy employed by management. The Company considers a combination of geologic and engineering factors to evaluate the need for impairment of these costs.

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Derivatives: Energen Resources periodically enters into commodity derivative contracts to manage its exposure to oil, natural gas and natural gas liquids price volatility. SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities as amended requires all derivatives to be recognized on the balance sheet and measured at fair value. Realized gains and losses from derivatives designated as cash flow hedges are recognized in oil and gas production revenues when the forecasted transaction occurs. Energen Resources may also enter into derivative transactions that do not qualify for cash flow hedge accounting but are considered by management to be valid economic hedges. Gains and losses from the change in fair value of derivative instruments that do not qualify for hedge accounting are reported in current period operating revenues, rather than in the period in which the hedge transaction is settled. Energen Resources does not enter into derivatives or other financial instruments for trading purposes. The use of derivative contracts to mitigate price risk may cause the Company s financial position, results of operations and cash flow to be materially different from results that would have been obtained had such risk mitigation activities not occurred.

Natural Gas Distribution

Regulated Operations: Alagasco applies SFAS No. 71, Accounting for the Effects of Certain Types of Regulation, to its regulated operations. This standard requires a cost to be capitalized as a regulatory asset that otherwise would be charged to expense if it is probable that the cost is recoverable in the future through regulated rates. Likewise, if current recovery is provided for a cost that will be incurred in the future, SFAS No. 71 requires the cost to be recognized as a regulatory liability. The Company anticipates SFAS No. 71 will continue as the applicable accounting standard for its regulated operations. Alagasco s rate setting methodology, Rate Stabilization and Equalization, has been in effect since 1983.

Consolidated

Employee Benefit Plans: In December 2006, the Company adopted SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132 (R) (SFAS No. 158). This Standard retains the previous periodic expense calculation on an actuarial basis under the provisions of SFAS No. 87, Employers Accounting for Pensions and SFAS No. 106, Employers Accounting for Postretirement Benefits Other than Pensions. In addition, SFAS No. 158 requires an employer to recognize the net funded status of defined benefit pensions and other postretirement benefit plans (benefit plans) as an asset or liability in its statement of financial position and to recognize changes in the funded status through comprehensive income in the year in which the changes occur. As required by SFAS No. 158 as of December 31, 2006, the pension benefit obligation is the projected benefit obligation (PBO), a measurement of earned benefit obligations at expected retirement salary levels; for other postretirement plans, the benefit obligation is the accumulated postretirement benefit obligation (APBO), a measurement of earned postretirement benefit obligations expected to be paid to employees upon retirement. Prior to implementation of SFAS No. 158, the required pension benefit obligation was the accumulated benefit obligation (ABO), a measurement of earned benefit obligations at existing salary levels, and other postretirement obligations were not recorded as a liability on the statement of financial position. Alagasco established a regulatory asset for the portion of the total benefit obligation to be recovered through rates in future periods in accordance with SFAS No. 71.

Actuarial assumptions attempt to anticipate future events and are used in calculating the expenses and liabilities related to these plans. The calculation of the liability related to the Company s benefit plans includes assumptions regarding the appropriate weighted average discount rate, the expected long-term rate of return on the plans assets and the estimated weighted average rate of increase in the compensation level of its employee base for defined benefit pension plans. The key assumptions used in determining these calculations are disclosed in Note 5, Employee Benefit Plans, in the Notes to Financial Statements.

In selecting the discount rate, consideration was given to Moody s Aa corporate bond rates, along with a yield curve applied to payments the Company expects to make out of its retirement plans. The yield curve is comprised of a broad base of Aa bonds with maturities between zero and thirty years. The discount rate was developed as the level equivalent rate that would produce the same present value as that using spot rates aligned with the projected benefit payments; the discount rate used to determine net periodic costs was 5.77 percent for each of the plans for the year ended December 31, 2007. The assumed rate of return on assets is the weighted average of expected long-term asset assumptions; the return on assets used to determine net periodic expense was 8.25 percent for each of the applicable plans for the year ended December 31, 2007. The estimated weighted average rate of increase in the compensation level for pay related plans was 4.2 percent for the year ended December 31, 2007.

The selection and use of actuarial assumptions affects the amount of benefit expense recorded in the Company s financial statements. The table below reflects a hypothetical 25 basis point change in assumed actuarial assumptions to pre-tax benefit expense for the year ended December 31, 2007:

(in thousands)	Pension Expense	Postretirement Expense
Discount rate change	$ 900	$ 100
Return on assets	$ 400	$ 200
Compensation increase	$ 700	$ -

The weighted average discount rate, return on plan assets and estimated rate of compensation increase used in the 2008 actuarial assumptions is 6.18 percent, 8.25 percent, and 4.07 percent, respectively.

Asset Retirement Obligation: The Company records the fair value of a liability for an asset retirement obligation (ARO) in the period in which it is incurred. Subsequent to initial measurement, liabilities are required to be accreted to their present value each period and capitalized costs are depreciated over the estimated useful life of the related assets. Upon settlement of the liability, the Company will settle the obligation for its recorded amount and recognize the resulting gain or loss. Energen Resources has an obligation to remove tangible equipment and restore land at the end of oil and gas production operations. Alagasco has certain removal cost obligations related to its gas distribution assets and a conditional asset retirement obligation to purge and cap its distribution and transmission lines upon abandonment. The estimate of future restoration and removal costs includes numerous assumptions and uncertainties, including but not limited to, inflation factors, discount rates, timing of settlement, and changes in contractual, regulatory, political, environmental, safety and public relations considerations.

Uncertain Tax Positions: As of January 1, 2007, the Company accounts for uncertain tax positions in accordance with the provisions of FIN 48. The application of income tax law is inherently complex; laws and regulation in this area are voluminous and often ambiguous. As such, the Company is required to make many subjective assumptions and judgments regarding income tax exposures. Interpretations and guidance related to income tax laws and regulation change over time. It is possible that changes in the Company s subjective assumptions and judgments could materially affect amounts recognized in the consolidated balance sheets and statements of income. Additional information related to the Company s uncertain tax position is provided in Note 17, Recent Pronouncements of the Financial Accounting Standards Board, in the Notes to the Financial Statements.

FORWARD-LOOKING STATEMENTS

Certain statements in this report express expectations of future plans, objectives and performance of the Company and its subsidiaries and constitute forward-looking statements made pursuant to the Safe Harbor provision of the Private Securities Litigation Reform Act of 1995. Except as otherwise disclosed, the Company s forward-looking statements do not reflect the impact of possible or pending acquisitions, investments, divestitures or restructurings. The absence of errors in input data, calculations and formulas used in estimates, assumptions and forecasts cannot be guaranteed. Neither the Company nor Alagasco undertakes any obligation to correct or update any forward-looking statements whether as a result of new information, future events or otherwise.

All statements based on future expectations rather than on historical facts are forward-looking statements that are dependent on certain events, risks and uncertainties that could cause actual results to differ materially from those anticipated. Some of these include, but are not limited to, economic and competitive conditions, inflation rates, legislative and regulatory changes, financial market conditions, our ability to access the capital markets, future business decisions, utility customer growth and retention and usage per customer, litigation results and other uncertainties, all of which are difficult to predict.

Third Party Facilities: The forward looking statements also assume generally uninterrupted access to third party oil and gas gathering, transportation, processing and storage facilities. Energen Resources relies upon such facilities for access to markets for its production. Alagasco relies upon such facilities for access to natural gas supplies. Such facilities are typically limited in number and geographically concentrated. An extended interruption of access to or service from these facilities, whether caused by weather events, natural disaster, accident, mechanical failure, criminal act or otherwise, could result in material adverse financial consequences to Alagasco, Energen Resources and/or the Company.

Energen Resources Production and Drilling: There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and in projecting future rates of production and timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates. In the event Energen Resources is unable to fully invest its planned acquisition, development and exploratory expenditures, future operating revenues, production, and proved reserves could be negatively affected. The drilling of development and exploratory wells can involve significant risks, including those related to timing, success rates and cost overruns, and these risks can be affected by lease and rig availability, complex geology and other factors. Anticipated drilling plans and capital expenditures may also change due to weather, manpower and equipment availability, changing emphasis by management and a variety of other factors which could result in actual drilling and capital expenditures being substantially different than currently planned.

Energen Resources Hedging: Although Energen Resources makes use of futures, swaps and fixed-price contracts to mitigate price risk, fluctuations in future oil, gas and natural gas liquids prices could materially affect the Company s financial position, results of operations and cash flows; furthermore, such risk mitigation activities may cause the Company s financial position and results of operations to be materially different from results that would have been obtained had such risk mitigation activities not occurred. The effectiveness of such risk mitigation assumes that counterparties maintain satisfactory credit quality. The effectiveness of such risk mitigation also assumes that actual sales volumes will generally meet or exceed the volumes subject to the futures, swaps and fixed price contracts. A substantial failure to meet sales volume targets whether caused by miscalculations, weather events, natural disaster, accident, criminal act or otherwise, could leave Energen Resources financially exposed to its counterparties and result in material adverse financial consequences to Energen Resources and the Company. The adverse effect could be increased if the adverse event was widespread enough to move market prices against Energen Resources position.

Alagasco s Hedging: Similarly, although Alagasco makes use of futures, swaps and fixed-price contracts to mitigate gas supply cost risk, fluctuations in future gas supply costs could materially affect its financial position and rates to customers. The effectiveness of Alagasco s risk mitigation assumes that its counterparties in such activities maintain satisfactory credit quality. The effectiveness of such risk mitigation also assumes that Alagasco s actual gas supply needs will generally meet or exceed the volumes subject to the futures, swaps and fixed price contracts. A substantial failure to experience projected gas supply needs, whether caused by miscalculations, weather events, natural disaster, accident, mechanical failure, criminal act or otherwise, could leave Alagasco financially exposed to its counterparties and result in material adverse financial consequences to Alagasco and the Company. The adverse effect could be increased if the adverse event was widespread enough to move market prices against Alagasco s position.

Operations: Inherent in the gas distribution activities of Alagasco and the oil and gas production activities of Energen Resources are a variety of hazards and operation risks, such as leaks, explosions and mechanical problems that could cause substantial financial losses. In addition, these risks could result in loss of human life, significant damage to property, environmental pollution, impairment of operations and substantial losses to the Company. In accordance with customary industry practices, the Company maintains insurance against some, but not all, of these risks and losses. The location of pipeline and storage facilities near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from these risks. The occurrence of any of these events could adversely affect Alagasco s, Energen Resources and/or the Company s financial position, results of operations and cash flows.

Alagasco s Service Territory: Alagasco s utility customers are geographically concentrated in central and north Alabama. Significant economic, weather, natural disaster, criminal act or other events that adversely affect this region could adversely affect Alagasco and the Company.

RECENT PRONOUNCEMENTS OF THE FINANCIAL ACCOUNTING STANDARDS BOARD (FASB)

The Company adopted the provisions of FIN 48 as of January 1, 2007. This Interpretation prescribed a recognition threshold and measurement attribute for the financial statement recognition, measurement and disclosure of a tax position taken or expected to be taken in a tax return. As a result of the implementation of FIN 48, the Company recognized an approximate $1.2 million increase in the liability for unrecognized tax benefits which was accounted for as a decrease to the January 1, 2007 balance of retained earnings. As of the date of adoption and after the impact of recognizing the increase in liability noted above, the Company s unrecognized tax benefits totaled $8.2 million. The amount of unrecognized tax benefits at January 1, 2007 that would favorably impact the Company s effective tax rate, if recognized, was $3.4 million. The Company recognized potential accrued interest and penalties related to unrecognized tax benefits in income tax expense. As of January 1, 2007, the Company recognized approximately $484,000 in potential interest (net of tax benefit) and penalties associated with uncertain tax positions.

During September 2006, the FASB issued SFAS No. 157, Fair Value Measurements, which clarifies that fair value should be based on the assumptions market participants would use when pricing an asset or a liability and establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. Under SFAS No. 157, fair value measurements would be separately disclosed by level within the fair value hierarchy effective for fiscal years beginning after November 15, 2007. The Company is currently evaluating the impact of this Statement. In February 2008, the FASB announced it will issue Final FASB Staff Positions (FSP s) that will partially defer the effective date of SFAS No. 157 for one year for certain nonfinancial assets and nonfinancial liabilities and remove certain leasing transactions from the scope of SFAS No. 157. The Company will evaluate the impact of the FSP s upon issuance.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities, which permits entities to measure financial instruments and certain other items at fair value to mitigate volatility in reported earnings. This Statement is effective for fiscal years beginning after November 15, 2007. The effect of this Standard on the Company is currently being evaluated.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), Business Combinations, which will improve the relevance, representational faithfulness, and comparability of the information that a reporting entity provides in its financial reports about a business combination and its effects. This Statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first fiscal year beginning on or after December 15, 2008. The Company is currently evaluating the impact of this Statement.

The FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51, in December 2007. SFAS No. 160 establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, changes in a parent s ownership interest, and the valuation of retained noncontrolling equity investments when a subsidiary is deconsolidated. SFAS No. 160 also establishes disclosure requirements that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. This Statement is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. The effect of this Standard on the Company is currently being evaluated.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by this item with respect to market risk is set forth in Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations under the heading Outlook and in Note 8, Financial Instruments and Risk Management, in the Notes to Financial Statements.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

ENERGEN CORPORATION

ALABAMA GAS CORPORATION

INDEX TO FINANCIAL STATEMENTS

AND FINANCIAL STATEMENT SCHEDULES

Schedules other than those listed above are omitted because they are not required, not applicable, or the required information is shown in the financial statements or notes thereto.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Energen Corporation:

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Energen Corporation and its subsidiaries at December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, appearing on Management s Report on Internal Control Over Financial Reporting under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company s internal control over financial reporting based on our integrated 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 17, Recent Pronouncements of the Financial Accounting Standards Board, and Note 5, Employee Benefit Plans, in the Notes to Financial Statements, the Company adopted FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes-an Interpretation of FASB Statement No. 109 and Statement of Financial Accounting Standard (SFAS) No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132 (R) , effective January 1, 2007 and December 31, 2006, respectively.

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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 (iii) 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.

/s/ PricewaterhouseCoopers LLP

Birmingham, Alabama

February 25, 2008

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of Alabama Gas Corporation:

In our opinion, the financial statements of Alabama Gas Corporation listed in the accompanying index present fairly, in all material respects, the financial position of Alabama Gas Corporation at December 31, 2007 and 2006, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2007 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related financial statements. These financial statements and financial statement schedule are the responsibility of the Company s management; our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 5, Employee Benefit Plans, in the Notes to Financial Statements, the Company adopted SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132 (R) , effective December 31, 2006.

/s/ PricewaterhouseCoopers LLP

Birmingham, Alabama

February 25, 2008

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CONSOLIDATED STATEMENTS OF INCOME

Energen Corporation

Years ended December 31, (in thousands, except share data)	**2007**	2006	2005
Operating Revenues			
Oil and gas operations	**$ 825,592**	$ 730,542	$ 527,694
Natural gas distribution	**609,468**	663,444	600,700
Total operating revenues	**1,435,060**	1,393,986	1,128,394
Operating Expenses			
Cost of gas	**318,429**	373,097	315,622
Operations and maintenance	**333,443**	302,157	268,727
Depreciation, depletion and amortization	**161,377**	142,086	131,691
Taxes, other than income taxes	**95,831**	95,727	93,983
Accretion expense	**3,948**	3,619	2,647
Total operating expenses	**913,028**	916,686	812,670
Operating Income	**522,032**	477,300	315,724
Other Income (Expense)			
Interest expense	**(47,100)**	(48,652)	(46,800)
Other income	**2,668**	951	2,163
Other expense	**(959)**	(1,046)	(710)
Total other expense	**(45,391)**	(48,747)	(45,347)
Income From Continuing Operations Before Income Taxes	**476,641**	428,553	270,377
Income tax expense	**167,429**	155,030	97,491
Income From Continuing Operations	**309,212**	273,523	172,886
Discontinued Operations, Net of Taxes			
Income (loss) from discontinued operations	**3**	(6)	(6)
Gain on disposal of discontinued operations	**18**	53	132
Income From Discontinued Operations	**21**	47	126
Net Income	**$ 309,233**	$ 273,570	$ 173,012
Diluted Earnings Per Average Common Share			
Continuing operations	**$ 4.28**	$ 3.73	$ 2.35
Discontinued operations	**-**	-	-
Net Income	**$ 4.28**	$ 3.73	$ 2.35
Basic Earnings Per Average Common Share			
Continuing operations	**$ 4.32**	$ 3.77	$ 2.37
Discontinued operations	**-**	-	-
Net Income	**$ 4.32**	$ 3.77	$ 2.37
Diluted Average Common Shares Outstanding	**72,180,861**	73,278,277	73,714,602
Basic Average Common Shares Outstanding	**71,591,551**	72,504,897	73,051,903

The accompanying Notes to Financial Statements are an integral part of these statements.

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CONSOLIDATED BALANCE SHEETS

Energen Corporation

(in thousands)	**December 31, 2007**	December 31, 2006
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 8,687**	$ 10,307
Accounts receivable, net of allowance for doubtful accounts of $12,244 and $13,961 at December 31, 2007 and 2006, respectively	**254,154**	329,766

Inventories, at average cost		
Storage gas inventory	**78,064**	68,769
Materials and supplies	**13,711**	9,281
Liquified natural gas in storage	**3,502**	3,766
Regulatory asset	**10,232**	35,479
Deferred income taxes	**54,166**	-
Prepayments and other	**26,514**	32,211
Total current assets	**449,030**	489,579
Property, Plant and Equipment		
Oil and gas properties, successful efforts method	**2,530,049**	2,163,065
Less accumulated depreciation, depletion and amortization	**664,290**	559,059
Oil and gas properties, net	**1,865,759**	1,604,006
Utility plant	**1,108,392**	1,060,562
Less accumulated depreciation	**448,053**	421,075
Utility plant, net	**660,339**	639,487
Other property, net	**12,145**	8,921
Total property, plant and equipment, net	**2,538,243**	2,252,414
Other Assets		
Regulatory asset	**32,238**	38,385
Prepaid pension costs and postretirement assets	**20,054**	19,975
Deferred charges and other	**40,088**	36,534
Total other assets	**92,380**	94,894
TOTAL ASSETS	**$ 3,079,653**	$ 2,836,887

The accompanying Notes to Financial Statements are an integral part of these statements.

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CONSOLIDATED BALANCE SHEETS

Energen Corporation

(in thousands, except share data)	**December 31, 2007**	December 31, 2006
LIABILITIES AND SHAREHOLDERS EQUITY		
Current Liabilities		
Long-term debt due within one year	**$ 10,000**	$ 100,000
Notes payable to banks	**134,000**	58,000
Accounts payable	**259,836**	194,448
Accrued taxes	**40,857**	42,960
Customers deposits	**21,425**	21,094
Amounts due customers	**20,534**	14,382
Accrued wages and benefits	**25,410**	24,548
Regulatory liability	**32,154**	33,871
Deferred income taxes	**-**	5,594
Other	**62,014**	65,985
Total current liabilities	**606,230**	560,882
Long-term debt	**562,365**	582,490
Deferred Credits and Other Liabilities		
Asset retirement obligation	**60,571**	53,980
Pension liabilities	**31,985**	32,504
Regulatory liability	**141,123**	135,466
Deferred income taxes	**238,706**	250,906

Other	**60,015**	18,590
Total deferred credits and other liabilities	**532,400**	491,446
Commitments and Contingencies		
Shareholders Equity		
Preferred stock, cumulative, $0.01 par value, 5,000,000 shares authorized	**-**	-
Common shareholders equity		
Common stock, $0.01 par value; 150,000,000 shares authorized, 74,190,786 shares issued at December 31, 2007 and 73,699,244 shares issued at December 31, 2006	**742**	737
Premium on capital stock	**434,999**	412,989
Capital surplus	**2,802**	2,802
Retained earnings	**1,119,816**	844,880
Accumulated other comprehensive gain (loss), net of tax		
Unrealized gain (loss) on hedges	**(65,057)**	50,555
Pension and postretirement plans, net of tax	**(21,167)**	(23,177)
Deferred compensation plan	**16,121**	13,956
Treasury stock, at cost; 3,374,336 shares and 3,253,337 shares at December 31, 2007 and 2006, respectively	**(109,598)**	(100,673)
Total shareholders equity	**1,378,658**	1,202,069
TOTAL LIABILITIES AND SHAREHOLDERS EQUITY	**$ 3,079,653**	$ 2,836,887

The accompanying Notes to Financial Statements are an integral part of these statements.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS EQUITY

Energen Corporation

	Common Stock					Accumulated				
(in thousands, except share data)	Number of Shares	Par Value	Premium on Capital Stock	Capital Surplus	Retained Earnings	Other Comprehensive Income (Loss)	Deferred Compensation Restricted Stock	Deferred Compensation Plan	Treasury Stock	Total Shareholders Equity
BALANCE DECEMBER 31, 2004	73,165,958	$ 732	$ 380,965	$ 2,802	$ 459,626	$ (37,330)	$ (2,675)	$ 28,919	$ (29,373)	$ 803,666
Net income					173,012					173,012
Other comprehensive income (loss):										
Current period change in fair value of derivative instruments, net of tax of ($100,484)						(163,947)				(163,947)
Reclassification adjustment, net of tax of $59,636						97,301				97,301
Minimum pension liability, net of tax of ($990)						(1,843)				(1,843)
Comprehensive income										104,523
Purchase of treasury shares									(2,459)	(2,459)
Shares issued for:										
Employee benefit plans	327,379	3	8,958						1,821	10,782
Deferred compensation obligation								(17,012)	17,012	
Issuance of restricted stock							(1,249)			(1,249)
Amortization of restricted stock							1,801			1,801
Stock based compensation			465							465
Tax benefit from employee stock plans			2,487							2,487
Long-range performance plan			1,986							1,986

Cash dividends - $0.40 per share					(29,324)					(29,324)
BALANCE DECEMBER 31, 2005	73,493,337	735	394,861	2,802	603,314	(105,819)	(2,123)	11,907	$ (12,999)	892,678
Net income					273,570					273,570
Other comprehensive income (loss):										
Current period change in fair value of derivative instruments, net of tax of $79,827						130,244				130,244
Reclassification adjustment, net of tax of $7,614						12,423				12,423
Pension and postretirement plans, net of tax of $3,062						5,686				5,686
Comprehensive income										421,923
Adjustment to initially apply SFAS No. 158, net of tax of ($8,161)						(15,156)				(15,156)
Purchase of treasury shares									(87,566)	(87,566)
Shares issued for:										
Employee benefit plans	205,907	2	1,444						1,941	3,387
Deferred compensation obligation								2,049	(2,049)	
Reclassification of restricted stock awards			(2,123)				2,123			
Amortization of restricted stock			2,252							2,252
Stock based compensation			196							196
Tax benefit from employee stock plans			1,980							1,980
Long-range performance plan			14,501							14,501
Forfeiture adjustment on stock plans			(122)							(122)
Cash dividends - $0.44 per share					(32,004)					(32,004)
BALANCE DECEMBER 31, 2006	73,699,244	737	412,989	2,802	844,880	27,378		13,956	$ (100,673)	1,202,069
Net income					309,233					309,233
Other comprehensive income (loss):										
Current period change in fair value of derivative instruments, net of tax of ($44,619)						(72,800)				(72,800)
Reclassification adjustment, net of tax of ($26,239)						(42,811)				(42,811)
Pension and postretirement plans, net of tax of $1,082						2,009				2,009
Comprehensive income										195,631
Adjustment to initially apply FIN 48					(1,181)					(1,181)
Purchase of treasury shares									(6,760)	(6,760)
Shares issued for:										
Employee benefit plans	491,542	5	9,671							9,676
Deferred compensation obligation								2,165	(2,165)	
Amortization of restricted stock			891							891
Stock based compensation			3,134							3,134
Tax benefit from employee stock plans			10,937							10,937
Long-range performance plan			(2,643)							(2,643)
Forfeiture adjustment on stock plans			20							20
Cash dividends - $0.46 per share					(33,116)					(33,116)
BALANCE DECEMBER 31, 2007	74,190,786	$ 742	$ 434,999	$ 2,802	$ 1,119,816	$ (86,224)	$	$ 16,121	$ (109,598)	$ 1,378,658

Share and per share data have been restated to reflect a 2-for-1 stock split effective June 1, 2005.

The accompanying Notes to Financial Statements are an integral part of these statements.

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CONSOLIDATED STATEMENTS OF CASH FLOWS

Energen Corporation

Years ended December 31, (in thousands)	**2007**	2006	2005
Operating Activities			
Net income	**$ 309,233**	$ 273,570	$ 173,012
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	**161,377**	142,086	131,719
Deferred income taxes	**1,162**	98,209	58,608
Change in derivative fair value	**(970)**	(2,043)	2,328
Gain on sale of assets	**(506)**	(55,916)	(1,928)
Other, net	**20,035**	4,255	(5,912)
Net change in:			
Accounts receivable, net	**71,810**	9,249	(70,944)
Inventories	**(13,461)**	1,084	(20,276)
Accounts payable	**(74,927)**	64,178	39,330
Amounts due customers	**21,247**	(38,940)	12,890
Other current assets and liabilities	**(10,833)**	(12,812)	16,297
Net cash provided by operating activities	**484,167**	482,920	335,124
Investing Activities			
Additions to property, plant and equipment	**(373,857)**	(302,177)	(230,715)
Acquisitions, net of cash acquired	**(56,323)**	(27,814)	(179,268)
Proceeds from sale of assets	**1,295**	75,429	10,832
Other, net	**(2,994)**	(2,337)	(1,573)
Net cash used in investing activities	**(431,879)**	(256,899)	(400,724)
Financing Activities			
Payment of dividends on common stock	**(33,116)**	(32,004)	(29,324)
Issuance of common stock	**2,051**	833	10,782
Purchase of treasury stock	**-**	(84,339)	(2,459)
Reduction of long-term debt	**(155,289)**	(15,898)	(84,796)
Proceeds from issuance of long-term debt	**45,000**	-	160,000
Debt issuance costs	**(494)**	-	(2,378)
Net change in short-term debt	**76,000**	(95,000)	18,000
Tax benefit on stock compensation	**10,937**	1,980	-
Other	**1,003**	-	-
Net cash provided by (used in) financing activities	**(53,908)**	(224,428)	69,825
Net change in cash and cash equivalents	**(1,620)**	1,593	4,225
Cash and cash equivalents at beginning of period	**10,307**	8,714	4,489
Cash and cash equivalents at end of period	**$ 8,687**	$ 10,307	$ 8,714

The accompanying Notes to Financial Statements are an integral part of these statements.

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STATEMENTS OF INCOME

Alabama Gas Corporation

Years ended December 31, (in thousands)	**2007**	2006	2005
Operating Revenues	**$ 609,468**	$ 663,444	$ 600,700
Operating Expenses			
Cost of gas	**318,429**	373,097	318,269
Operations and maintenance	**129,351**	126,948	126,041
Depreciation	**47,136**	44,244	42,351
Income taxes			
Current	**15,415**	19,745	20,556
Deferred	**6,221**	2,257	1,804
Taxes, other than income taxes	**41,810**	44,881	41,117
Total operating expenses	**558,362**	611,172	550,138
Operating Income	**51,106**	**52,272**	**50,562**
Other Income (Expense)			
Allowance for funds used during construction	**611**	951	792
Other income	**1,665**	1,490	1,371
Other expense	**(868)**	(961)	(701)
Total other income	**1,408**	1,480	1,462
Interest Charges			
Interest on long-term debt	**11,956**	12,836	13,752
Other interest charges	**3,740**	3,618	1,308
Total interest charges	**15,696**	16,454	15,060
Net Income	**$ 36,818**	$ 37,298	$ 36,964

The accompanying Notes to Financial Statements are an integral part of these statements.

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BALANCE SHEETS

Alabama Gas Corporation

(in thousands)	**December 31, 2007**	December 31, 2006
ASSETS		
Property, Plant and Equipment		
Utility plant	**$ 1,108,392**	$ 1,060,562
Less accumulated depreciation	**448,053**	421,075
Utility plant, net	**660,339**	639,487
Other property, net	**157**	163
Current Assets		
Cash	**7,335**	8,765
Accounts receivable		
Gas	**139,761**	159,101

Other	**6,336**	10,708
Allowance for doubtful accounts	**(11,500)**	(13,200)
Inventories, at average cost		
Storage gas inventory	**78,064**	68,769
Materials and supplies	**3,866**	4,199
Liquified natural gas in storage	**3,502**	3,766
Regulatory asset	**10,232**	35,479
Deferred income taxes	**25,179**	25,222
Prepayments and other	**2,247**	3,557
Total current assets	**265,022**	306,366
Other Assets		
Regulatory asset	**32,238**	38,385
Prepaid pension costs and postretirement assets	**15,831**	15,369
Deferred charges and other	**7,226**	6,326
Total other assets	**55,295**	60,080
TOTAL ASSETS	$ **980,813**	$ 1,006,096

The accompanying Notes to Financial Statements are an integral part of these statements.

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BALANCE SHEETS

Alabama Gas Corporation

(in thousands, except share data)	**December 31, 2007**	December 31, 2006
LIABILITIES AND CAPITALIZATION		
Capitalization		
Preferred stock, cumulative, $0.01 par value, 120,000 shares authorized	**$ -**	$ -
Common shareholder s equity		
Common stock, $0.01 par value; 3,000,000 shares authorized, 1,972,052 shares issued at December 31, 2007 and 2006, respectively	**20**	20
Premium on capital stock	**31,682**	31,682
Capital surplus	**2,802**	2,802
Retained earnings	**261,979**	250,560
Total common shareholder s equity	**296,483**	285,064
Long-term debt	**208,467**	208,756
Total capitalization	**504,950**	493,820
Current Liabilities		
Notes payable to banks	**62,000**	58,000
Accounts payable	**80,067**	118,936
Affiliated companies	**4,934**	18,130
Accrued taxes	**30,858**	37,813
Customers deposits	**21,425**	21,094
Amounts due customers	**20,534**	14,382
Accrued wages and benefits	**10,062**	9,714
Regulatory liability	**32,154**	33,871
Other	**10,417**	8,225
Total current liabilities	**272,451**	320,165

Deferred Credits and Other Liabilities		
Deferred income taxes	**59,790**	54,166
Regulatory liability	**141,123**	135,466
Customer advances for construction and other	**2,499**	2,479
Total deferred credits and other liabilities	**203,412**	192,111
Commitments and Contingencies		
TOTAL LIABILITIES AND CAPITALIZATION	**$ 980,813**	$ 1,006,096

The accompanying Notes to Financial Statements are an integral part of these statements.

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STATEMENTS OF SHAREHOLDER S EQUITY

Alabama Gas Corporation

(in thousands, except share data)

	Common Stock					Total
	Number of Shares	Par Value	Premium on Capital Stock	Capital Surplus	Retained Earnings	Shareholder s Equity
Balance December 31, 2004	1,972,052	$ 20	$ 31,682	$ 2,802	$ 223,515	$ 258,019
Net income					36,964	36,964
Cash dividends					(23,522)	(23,522)
Balance December 31, 2005	1,972,052	20	31,682	2,802	236,957	271,461
Net income					37,298	37,298
Cash dividends					(23,695)	(23,695)
Balance December 31, 2006	1,972,052	20	31,682	2,802	250,560	285,064
Net income					36,818	36,818
Cash dividends					(25,399)	(25,399)
Balance December 31, 2007	1,972,052	$ 20	$ 31,682	$ 2,802	$ 261,979	$ 296,483

The accompanying Notes to Financial Statements are an integral part of these statements.

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STATEMENTS OF CASH FLOWS

Alabama Gas Corporation

Years ended December 31, (in thousands)	**2007**	2006	2005
Operating Activities			
Net income	**$ 36,818**	$ 37,298	$ 36,964

Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**47,136**	44,244	42,351
Deferred income taxes	**6,221**	2,257	1,804
Other, net	**3,036**	(5,019)	(3,025)
Net change in:			
Accounts receivable, net	**19,501**	37,260	(48,623)
Inventories	**(8,698)**	2,384	(20,056)
Accounts payable	**(27,702)**	1,240	24,560
Amounts due customers	**21,247**	(38,940)	12,890
Other current assets and liabilities	**(4,000)**	3,190	9,371
Net cash provided by operating activities	**93,559**	83,914	56,236
Investing Activities			
Additions to property, plant and equipment	**(58,154)**	(75,107)	(72,388)
Net advances from (to) parent company	**-**	3,215	(1,025)
Other, net	**(2,460)**	(1,963)	(1,551)
Net cash used in investing activities	**(60,614)**	(73,855)	(74,964)
Financing Activities			
Payment of dividends on common stock	**(25,399)**	(23,695)	(23,522)
Reduction of long-term debt	**(45,289)**	(5,898)	(84,796)
Proceeds from issuance of long-term debt	**45,000**	-	160,000
Debt issuance costs	**(494)**	-	(2,252)
Net advances from parent company	**(13,196)**	18,130	-
Net change in short-term debt	**4,000**	3,000	(27,000)
Other	**1,003**	-	-
Net cash provided (used) by financing activities	**(34,375)**	(8,463)	22,430
Net change in cash and cash equivalents	**(1,430)**	1,596	3,702
Cash and cash equivalents at beginning of period	**8,765**	7,169	3,467
Cash and cash equivalents at end of period	**$ 7,335**	$ 8,765	$ 7,169

The accompanying Notes to Financial Statements are an integral part of these statements.

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NOTES TO FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Energen Corporation (Energen or the Company) is a diversified energy holding company engaged primarily in the development, acquisition, exploration and production of oil and gas in the continental United States (oil and gas operations) and in the purchase, distribution, and sale of natural gas principally in central and north Alabama (natural gas distribution). The following is a description of the Company s significant accounting policies and practices.

A. Principles of Consolidation

The accompanying consolidated financial statements include the accounts of the Company and its subsidiaries, principally Energen Resources Corporation and Alabama Gas Corporation (Alagasco), after elimination of all significant intercompany transactions in consolidation. Certain reclassifications have been made to conform the prior years financial statements to the current-year presentation.

B. Oil and Gas Operations

Property and Related Depletion: Energen Resources follows the successful efforts method of accounting for costs incurred in the exploration and development of oil, gas and natural gas liquid reserves. Lease acquisition costs are capitalized initially, and unproved properties are reviewed periodically to determine if there has been impairment of the carrying value, with any such impairment charged to exploration expense currently. All development costs are capitalized. Exploratory drilling costs are capitalized pending determination of proved reserves. If proved reserves are not discovered, the exploratory drilling costs are expensed. Other exploration costs, including geological and geophysical costs, are expensed as incurred. Depreciation, depletion and amortization expense is determined on a field-by-field basis using the units-of-production method based on proved reserves. Anticipated abandonment and restoration costs are capitalized and depreciated using the units-of-production method based on proved developed reserves.

Operating Revenue: Energen Resources utilizes the sales method of accounting to recognize oil, gas and natural gas liquids production revenue. Under the sales method, revenues are based on actual sales volumes of commodities sold to purchasers. Over-production liabilities are established only when it is estimated that a property s over-produced volumes exceed the net share of remaining reserves for such property. Energen Resources had no material production imbalances at December 31, 2007 and 2006.

Derivative Commodity Instruments: Energen Resources periodically enters into derivative commodity instruments to hedge its price exposure to its estimated oil, natural gas and natural gas liquids production. Such instruments may include regulated natural gas and crude oil futures contracts traded on the New York Mercantile Exchange (NYMEX) and over-the-counter swaps, collars and basis hedges with major energy derivative product specialists. The counterparties to the commodity instruments are investment banks and energy-trading firms. In some contracts, the amount of credit allowed before Energen Resources must post collateral for out-of-the-money hedges varies depending on the credit rating of the Company. In cases where these arrangements exist, the credit ratings must be maintained at investment grade status to have any available counterparty credit. Adverse changes to the Company s credit rating results in decreasing amounts of credit available under these contracts. The counterparties for these contracts do not extend credit to the Company in the event credit ratings are below investment grade.

Energen Resources applies Statement of Financial Accounting Standard (SFAS) No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended which requires all derivatives be recognized on the balance sheet and measured at fair value. If a derivative is designated as a cash flow hedge, the effectiveness of the hedge, or the degree that the gain (loss) for the hedging instrument offsets the loss (gain) on the hedged item is measured at each reporting period. The effective portion of the gain or loss on the derivative instrument is

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recognized in other comprehensive income as a component of shareholders equity and subsequently reclassified to operating revenues when the forecasted transaction affects earnings. The ineffective portion of a derivative s change in fair value is recognized in operating revenues immediately. Derivatives that do not qualify for hedge treatment under SFAS No. 133 are recorded at fair value with gains or losses recognized in operating revenues in the period of change. All derivative transactions are included in operating activities on the Consolidated Statements of Cash Flows.

Additionally, the Company may also enter into derivatives that do not qualify for cash flow hedge accounting but are considered by management to represent valid economic hedges and are accounted for as mark-to-market transactions. These economic hedges may include, but are not limited to, basis hedges without a corresponding NYMEX hedge, put options and hedges on non-operated or other properties for which all of the necessary information to qualify for cash flow hedge accounting is either not readily available or subject to change.

All hedge transactions are pursuant to standing authorizations by the Board of Directors, which do not permit speculative positions. The Company formally documents all relationships between hedging instruments and hedged items at the inception of the hedge, as well as its risk management objective and strategy for undertaking the hedge. This process includes specific identification of the hedging instrument and the hedge transaction, the nature of the risk being hedged and how the hedging instrument s effectiveness in hedging the exposure to the hedged transaction s variability in cash flows attributable to the hedged risk will be assessed. Both at the inception of the hedge and on an ongoing basis, the Company assesses whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items. The Company discontinues hedge accounting if a derivative has ceased to be a highly effective hedge. The maximum term over which Energen Resources has hedged exposures to the variability of cash flows is through December 31, 2010.

Long-Lived Assets and Discontinued Operations: The Company applies SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, which requires the Company to reflect gains and losses on the sale of certain oil and gas properties and any impairments of properties held-for-sale be reported as discontinued operations, with income or loss from operations of the associated properties reported as income or loss from discontinued operations. The results of operations for certain held-for-sale properties are reclassified and reported as discontinued operations for prior periods in accordance with SFAS No. 144. Energen Resources may, in the ordinary course of business, be involved in the sale of developed or undeveloped properties. All assets held-for-sale are reported at the lower of the carrying amount or fair value.

C. Natural Gas Distribution

Utility Plant and Depreciation: Property, plant and equipment are stated at cost. The cost of utility plant includes an allowance for funds used during construction. Maintenance is charged for the cost of normal repairs and the renewal or replacement of an item of property which is less than a retirement unit. When property which represents a retirement unit is replaced or removed, the cost of such property is credited to utility plant and is charged to the accumulated reserve for depreciation. The estimated net removal costs on certain gas distribution assets are charged through depreciation and recognized as a regulatory liability in accordance with regulatory accounting. Depreciation is provided on the straight-line method over the estimated useful lives of utility property at rates established by the Alabama Public Service Commission (APSC). Approved depreciation rates averaged approximately 4.5 percent in the years ended December 31, 2007, 2006 and 2005.

Inventories: Inventories, which consist primarily of gas stored underground, are stated at average cost.

Operating Revenue and Gas Costs: Alagasco records natural gas distribution revenues in accordance with its tariff established by the APSC. The margin and gas costs on service delivered to cycle customers but not yet billed are recorded in current assets as accounts receivable with a corresponding regulatory liability. Gas imbalances are settled on a monthly basis. Alagasco had no material gas imbalances at December 31, 2007 and 2006.

Regulatory Accounting: Alagasco is subject to the provisions of SFAS No. 71, Accounting for the Effects of Certain Types of Regulation. In general, SFAS No. 71 requires utilities to capitalize or defer certain costs or revenues, based upon approvals received from regulatory authorities, to be recovered from or refunded to customers in future periods.

Derivative Commodity Instruments: On December 4, 2000, the APSC authorized Alagasco to engage in energy-risk management activities. Accordingly, Alagasco may enter into cash flow derivative commodity instruments to hedge its exposure to price fluctuations on its gas supply. As required by SFAS No. 133, Alagasco recognizes all derivatives as either assets or liabilities on the balance sheet. Any gains or losses are passed through to customers using the mechanisms of the Gas Supply Adjustment (GSA) rider in accordance with Alagasco s APSC approved tariff and are recognized as a regulatory asset or regulatory liability as required by SFAS No. 71.

Taxes on revenues: Collections and payments of excise taxes are reported on a gross basis. These amounts are included in taxes other than income taxes on the consolidated statements of income as follows:

Years ended December 31, (in thousands)	**2007**	2006	2005
Taxes on revenues	**$ 31,067**	$ 33,983	$ 30,899

The collection and payment of utility gross receipts tax and utility service use tax are presented on a net basis.

D. Income Taxes

The Company uses the liability method of accounting for income taxes in accordance with SFAS No. 109, Accounting for Income Taxes. Under this method, a deferred tax asset or liability is recognized for the estimated future tax effects attributable to temporary differences between the financial statement basis and the tax basis of assets and liabilities as well as tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the period of the change. The Company and its subsidiaries file a consolidated federal income tax return. Consolidated federal income taxes are charged to appropriate subsidiaries using the separate return method.

E. Accounts Receivable and Allowance for Doubtful Accounts

Trade accounts receivable are recorded at the invoiced amounts and do not bear interest. The allowance for doubtful accounts is the Company s best estimate of the amount of probable credit losses in the existing accounts receivable. The Company determines the allowance based on historical experience and reviews the allowance for doubtful accounts monthly. Account balances are charged against the allowance when it is anticipated the receivable will not be recovered.

F. Cash Equivalents

The Company includes highly liquid marketable securities and debt instruments purchased with a maturity of three months or less in cash equivalents.

G. Earnings Per Share

The Company s basic earnings per share amounts have been computed based on the weighted-average number of common shares outstanding. Diluted earnings per share amounts reflect the assumed issuance of common shares for all potentially dilutive securities (see Note 9, Reconciliation of Earnings Per Share).

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H. Stock-Based Compensation

The Company adopted SFAS No. 123 (revised 2004), Share-Based Payment (SFAS No. 123R), using the modified prospective application method for new awards effective January 1, 2006. The Company previously adopted the fair value recognition provisions of SFAS No. 123 as amended, Accounting for Stock-Based Compensation, prospectively for stock-based compensation effective January 1, 2003. As a result, the adoption of SFAS No. 123R did not have a significant impact to the Company since the expensing provisions were voluntarily adopted in 2003.

SFAS No. 123R requires that all share-based compensation awards be measured at fair value at the date of grant and expensed over the requisite vesting period. SFAS No. 123R requires forfeitures to be estimated at the time of grant and revised, if necessary, in subsequent periods if the actual forfeitures differ from those estimates. Prior to the adoption of SFAS No. 123R, the Company accounted for forfeitures upon occurrence. This change in method did not have a significant impact to the Company upon adoption of SFAS No. 123R.

The Company previously recognized all stock-based employee compensation expense over the stated vesting periods for each award. For awards granted prior to January 1, 2006, the Company recorded any unrecognized expense on the date of an employee s retirement. For new awards granted to retirement eligible employees effective January 1, 2006, the Company began recognizing the entire compensation expense in the period of grant. If this method of expense recognition had been applied to all awards during 2007, 2006 and 2005, compensation expense would have been reduced by approximately $1.1 million, $2.1 million and $0.8 million, respectively**.** The Company utilized the long-form method of calculating the available pool of windfall tax benefit. For 2007 and 2006, the Company recognized an excess tax benefit of $10.9 million and $2 million related to its stock-based compensation.

The following table illustrates the effect on net income and diluted and basic earnings per share as if the Company had applied the fair value recognition provisions of SFAS No. 123, superseded by SFAS No. 123R, to all outstanding and unvested employee share-based awards during 2005:

Year ended December 31, (in thousands)	2005
Net income	
As reported	$ 173,012
Stock based compensation expense included in reported net income, net of tax	8,131
Stock based compensation expense determined under the fair value based method, net of tax	(6,238)
Pro forma	$ 174,905
Diluted earnings per average common share	
As reported	$ 2.35
Pro forma	$ 2.37
Basic earnings per average common share	
As reported	$ 2.37
Pro forma	$ 2.39

I. Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reporting period. The major estimates and assumptions identified by management include, but are not limited to, estimates of physical quantities of oil and gas reserves, periodic assessments of oil and gas properties for impairment, an assumption that SFAS No. 71 will continue as the applicable accounting standard for the Company s regulated operations and estimates used in determining the Company s obligations under its employee pension plans and asset retirement obligations. Due to the inherent uncertainty involved in making estimates, actual results reported in future periods may differ from the estimates.

J. Environmental Costs

Environmental compliance costs, including ongoing maintenance, monitoring and similar costs, are expensed as incurred. Environmental remediation costs are accrued when remedial efforts are probable and the cost can be reasonably estimated.

2. REGULATORY MATTERS

All of Alagasco s utility operations are conducted in the state of Alabama. Alagasco is subject to regulation by the APSC which established the Rate Stabilization and Equalization (RSE) rate-setting process in 1983. RSE was extended with modifications in 2007, 2002, 1996, 1990, 1987 and 1985. On December 21, 2007, the APSC extended Alagasco s rate-setting methodology, RSE, with certain modifications as outlined below, for a seven-year period through December 31, 2014. Under the terms of the extension, RSE will continue after December 31, 2014, unless, after notice to the Company and a hearing, the APSC votes to modify or discontinue the RSE methodology. Alagasco is on a September 30 fiscal year for rate-setting purposes (rate year) and reports on a calendar year for the Securities and Exchange Commission and all other financial accounting reporting purposes.

Alagasco s allowed range of return on equity remains 13.15 percent to 13.65 percent throughout the term of the order. Under RSE the APSC conducts quarterly reviews to determine, based on Alagasco s projections and year-to-date performance, whether Alagasco s return on average equity at the end of the rate year will be within the allowed range of return. Reductions in rates can be made quarterly to bring the projected return within the allowed range; increases, however, are allowed only once each rate year, effective December 1, and cannot exceed 4 percent of prior-year revenues. As of September 30, 2007 and 2005, Alagasco had a $3.6 million and a $3.3 million pre-tax, respectively, reduction in revenues to bring the return on average equity to midpoint within the allowed range of return. Under the provisions of RSE, corresponding reductions in rates for 2007 were effective October 1, 2007 and December 1, 2007, and for 2005 effective December 1, 2005, Alagasco did not have a reduction in rates related to the return on average equity for rate year ended 2006. A $12 million, $14.3 million and $15.8 million annual increase in revenues became effective December 1, 2007, 2006, and 2005, respectively.

Prior to the December 21, 2007 extension, RSE limited the utility s equity upon which a return is permitted to 60 percent of total capitalization. Subsequent to the extension, the equity on which a return will be permitted will be phased down to 57 percent by December 31, 2008 and 55 percent by December 31, 2009.

Prior to the extension, under the inflation-based Cost Control Measurement (CCM) established by the APSC, if the percentage change in operations and maintenance (O&M) expense per customer fell within a range of 1.25 points above or below the percentage change in the Consumer Price Index For All Urban Consumers (index range), no adjustment was required. If the change in O&M expense per customer exceeded the index range, three-quarters of the difference was returned to customers. To the extent the change was less than the index range, the utility benefited by one-half of the difference through future rate adjustments. The changes to the O&M expense cost control measurement subsequent to the extension are as follows: annual changes in O&M expense will be measured on an aggregate basis rather than per customer; the percentage change in O&M expense must fall within a range of 0.75 points above or below the percentage change in the index range; certain items that fluctuate based on situations demonstrated to be beyond Alagasco s control may be excluded for the cost control measurement calculation; the O&M expense base for measurement purposes will continue to be set at the prior year s actual O&M expense amount unless the Company exceeds the top of the index range in two successive years, in which case the base for the following year will be set at the top of the index range.

Alagasco s O&M expense fell within the index range for the rate years ended September 30, 2007 and 2005. The increase in O&M expense per customer was above the index range for the rate year ended September 30, 2006; as a result, the utility had a $1.5 million pre-tax decrease in revenues with the related rate reduction effective December 1, 2006.

Alagasco calculates a temperature adjustment to customers monthly bills to moderate the impact of departures from normal temperatures on Alagasco s earnings. Adjustments to customers bills are made in the same billing cycle in which the weather variation occurs. The temperature adjustment applies primarily to residential, small commercial and small industrial customers. This adjustment, however, is subject to regulatory limitations on increases to customers bills. Other non-temperature weather related conditions that may affect customer usage are not included in the temperature adjustment such as the impact of wind velocity or cloud cover and the elasticity of demand as a result of higher commodity prices. Alagasco s rate schedules for natural gas distribution charges contain a GSA rider, established in 1993, which permits the pass-through to customers of changes in the cost of gas supply.

The APSC approved an Enhanced Stability Reserve (ESR), beginning rate year 1998 with an approved maximum funding level of $4 million, to which Alagasco may charge the full amount of: (1) extraordinary O&M expenses resulting from *force majeure* events such as storms, severe weather, and outages, when one or a combination of two such events results in more than $200,000 of additional O&M expense during a rate year; or (2) individual industrial and commercial customer revenue losses that exceed $250,000 during the rate year, if such losses cause Alagasco s return on average equity to fall below 13.15 percent. Following a year in which a charge against the ESR is made, the APSC provides for accretions to the ESR of no more than $40,000 monthly until the maximum funding level is achieved. ESR balances of $4 million at December 31, 2007 and 2006, respectively, are included in the consolidated financial statements. Subsequent to the 2007 extension, Alagasco will not have accretions against the ESR until December 31, 2010 unless the Company incurs a significant natural disaster during the three-year period ended December 31, 2010 and receives approval from the APSC to resume accretions under the ESR.

The excess of total acquisition costs over book value of net assets of acquired municipal gas distribution systems is included in utility plant and is being amortized through Alagasco s rate-setting mechanism on a straight-line basis over approximately 23 years. At December 31, 2007 and 2006, the net acquisition adjustments were $8.1 million and $9.3 million, respectively.

3. LONG-TERM DEBT AND NOTES PAYABLE

Long-term debt consisted of the following:

(in thousands)	**December 31, 2007**	December 31, 2006
Energen Corporation:		
Medium-term Notes, Series A and B, interest ranging from 6.95% to 7.625%, for notes due July 15, 2008, to February 15, 2028	**$ 315,000**	$ 325,000
5% Notes, due October 1, 2013	**50,000**	50,000
Floating Rate Senior Notes	**-**	100,000
Alabama Gas Corporation:		
Medium-term Notes, Series A, interest of 7.57%, due September 20, 2011	**5,000**	15,000
6.75% Notes	**-**	34,445
5.20% Notes, due January 15, 2020	**40,000**	40,000
5.70% Notes, due January 15, 2035	**38,467**	39,311
5.368% Notes, due December 1, 2015	**80,000**	80,000
5.90% Notes, due January 15, 2037	**45,000**	-
Total	**573,467**	683,756
Less amounts due within one year	**10,000**	100,000
Less unamortized debt discount	**1,102**	1,266
Total	$ 562,365	$ 582,490

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The aggregate maturities of Energen s long-term debt for the next five years are as follows:

Years ending December 31, *(in thousands)*

2008	**2009**	**2010**	**2011**	**2012**
$ 10,000	-	$ 150,000	$ 5,000	$ 1,000

The aggregate maturities of Alagasco s long-term debt for the next five years are as follows:

Years ending December 31, *(in thousands)*				
2008	**2009**	**2010**	**2011**	**2012**
-	-	-	$ 5,000	-

The Company is in compliance with the financial covenants under its various long-term debt agreements. Except as discussed below, debt covenants also address routine matters such as timely payment of principal and interest, maintenance of corporate existence and restrictions on liens. The Company s outstanding debt is subject to a cross default provision under Energen s Indenture dated September 1, 1996 with The Bank of New York as Trustee. In the event Alagasco or Energen Resources had a debt default of more than $10 million it would also be considered an event of default by Energen under the 1996 Indenture. All of the Company s debt is unsecured. No conditions exist under long-term debt agreements which could restrict the Company s ability to pay dividends.

In May 2007, Energen voluntarily called $100 million Floating Rate Senior Notes due November 15, 2007. In April 2007, Energen voluntarily redeemed $10 million of Medium-Term Notes, Series A, with an annual interest rate of 8.09% due September 15, 2026. Associated with this redemption, the Company incurred a call premium of 4.045%. In January 2007, Alagasco issued $45 million of long-term debt with an interest rate of 5.9% due January 15, 2037. Alagasco used these long-term debt proceeds to redeem the $34.4 million of 6.75% Notes, maturing September 1, 2031 and $10 million of 7.97% Medium-Term Notes maturing September 23, 2026.

As of December 31, 2007, the Company had short-term credit lines and other credit facilities with various financial institutions aggregating $415 million of which Energen had available $255 million, Alagasco had available $110 million and $50 million available to either Company for working capital needs. Alagasco has been authorized by the APSC to borrow up to $200 million at any one time outstanding under short-term lines of credit. As of December 31, 2007, the Company is in compliance with the financial covenants under the various short-term loan agreements. Certain of the Company s credit facilities in the aggregate amount of $85 million, including $75 million for Energen and $10 million for Alagasco, have a covenant that the ratio of consolidated debt to consolidated capitalization will not exceed 0.65:1. The following is a summary of information relating to notes payable to banks:

(in thousands)	**December 31, 2007**	December 31, 2006
Energen outstanding	**$ 72,000**	$ -
Alagasco outstanding	**62,000**	58,000
Notes payable to banks	**134,000**	58,000
Available for borrowings	**281,000**	307,000
Total	**$ 415,000**	$ 365,000
Energen maximum amount outstanding at any month-end	**$ 134,000**	$ 117,000
Energen average daily amount outstanding	**$ 67,734**	$ 63,658
Energen weighted average interest rates based on:		
Average daily amount outstanding	**5.35%**	5.32%
Amount outstanding at year-end	**4.64%**	5.70%
Alagasco maximum amount outstanding at any month-end	**$ 62,000**	$ 58,000
Alagasco average daily amount outstanding	**$ 29,518**	$ 37,104
Alagasco weighted average interest rates based on:		
Average daily amount outstanding	**5.39%**	5.43%
Amount outstanding at year-end	**4.62%**	5.70%

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Energen s total interest expense was $47,100,000, $48,652,000 and $46,800,000 for the years ended December 31, 2007, 2006 and 2005, respectively. Total interest expense for Alagasco was $15,696,000, $16,454,000 and $15,060,000 for the years ended December 31, 2007, 2006 and 2005, respectively.

4. INCOME TAXES

The components of Energen s income taxes consisted of the following:

Years ended December 31, (in thousands)	**2007**	2006	2005

Taxes estimated to be payable currently:			
Federal	**$ 149,787**	$ 47,799	$ 29,765
State	**16,480**	9,022	6,078
Total current	**166,267**	56,821	35,843
Taxes deferred:			
Federal	**838**	93,605	59,685
State	**324**	4,604	1,963
Total deferred	**1,162**	98,209	61,648
Total income tax expense from continuing operations	**$ 167,429**	$ 155,030	$ 97,491

For the years ended December 31, 2007 and 2006, Energen recorded a current income tax expense of $12,000 and $29,000, respectively, related to income from discontinued operations. For the year ended December 31, 2005, Energen recorded a current income tax expense of $3,117,000 and a deferred tax benefit of $3,040,000 related to income from discontinued operations.

The components of Alagasco s income taxes consisted of the following:

Years ended December 31, (in thousands)	**2007**	2006	2005
Taxes estimated to be payable currently:			
Federal	**$ 13,604**	$ 17,472	$ 18,430
State	**1,811**	2,273	2,126
Total current	**15,415**	19,745	20,556
Taxes deferred:			
Federal	**5,510**	1,999	1,597
State	**711**	258	207
Total deferred	**6,221**	2,257	1,804
Total income tax expense	**$ 21,636**	$ 22,002	$ 22,360

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Temporary differences and carryforwards which gave rise to Energen s and Alagasco s deferred tax assets and liabilities were as follows:

Energen Corporation

(in thousands)	**December 31, 2007**		December 31, 2006	
	Current	**Noncurrent**	Current	Noncurrent
Deferred tax assets:				
Minimum tax credit	**$ -**	$ -	$ -	$ 1,267
Unbilled and deferred revenue	**10,648**	-	10,269	-
Enhanced stability reserve and other regulatory costs	**1,497**	-	2,009	-
Allowance for doubtful accounts	**4,567**	**-**	5,216	-
Insurance accruals	**2,564**	**-**	2,693	-
Compensation accruals	**8,655**	**-**	8,460	-
Inventories	**1,230**	**-**	889	-
Other comprehensive income	**23,995**	**27,275**	-	17,017
Gas supply adjustment accruals	**1,486**	**-**	1,309	-
State net operating losses and other carryforwards	**-**	**3,024**	-	2,698
Other	**2,789**	**153**	2,705	602
Total deferred tax assets	**57,431**	**30,452**	33,550	21,584
Valuation allowance	**(2,137)**	**(887)**	(1,928)	(770)
Total deferred tax assets	**55,294**	**29,565**	31,622	20,814

Deferred tax liabilities:				
Depreciation and basis differences	**-**	**261,137**	-	261,960
Pension and other costs	**-**	**6,094**	-	9,760
Other comprehensive income	**-**	**-**	35,523	-
Other	**1,128**	**1,040**	1,693	-
Total deferred tax liabilities	**1,128**	**268,271**	37,216	271,720
Net deferred tax assets (liabilities)	**$ 54,166**	**$ (238,706)**	$ (5,594)	$ (250,906)

Alabama Gas Corporation *(in thousands)*	**December 31, 2007**		December 31, 2006	
	Current	**Noncurrent**	Current	Noncurrent
Deferred tax assets:				
Unbilled and deferred revenue	**$ 10,648**	**$ -**	$ 10,269	$ -
Enhanced stability reserve and other regulatory costs	**1,497**	**-**	2,009	-
Allowance for doubtful accounts	**4,348**	**-**	4,991	-
Insurance accruals	**2,804**	**-**	2,092	-
Compensation accruals	**3,132**	**-**	3,639	-
Inventories	**1,230**	**-**	889	-
Gas supply adjustment accruals	**1,486**	**-**	1,309	-
Other	**704**	**115**	830	487
Total deferred tax assets	**25,849**	**115**	26,028	487
Deferred tax liabilities:				
Depreciation and basis differences	**-**	**48,892**	-	42,682
Pension and other costs	**-**	**11,013**	-	11,971
Other	**670**	**-**	806	-
Total deferred tax liabilities	**670**	**59,905**	806	54,653
Net deferred tax assets (liabilities)	**$ 25,179**	**$ (59,790)**	$ 25,222	$ (54,166)

The Company files a consolidated federal income tax return with all of its subsidiaries. As of December 31, 2007, the Company has fully utilized the minimum tax credit carryforward that was previously recognized as a reduction of income tax expense. The minimum tax credit relates to alternative minimum taxes previously paid that are allowed to be carried forward to offset future cash tax liabilities. The Company has a full valuation allowance recorded against a deferred tax asset of $3,024,000 arising from certain state net operating loss and charitable contribution carryforwards. The Company intends to fully reserve this asset until it is determined that it is more likely than not that the asset can be realized through future taxable income in the respective state taxing jurisdictions. No other valuation allowance with respect to deferred taxes is deemed necessary as the Company anticipates generating adequate future taxable income to realize the benefits of all remaining deferred tax assets on the consolidated balance sheets.

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Total income tax expense for the Company differed from the amount which would have been provided by applying the statutory federal income tax rate of 35 percent to earnings before taxes from continuing operations as illustrated below:

Years ended December 31, (in thousands)	**2007**	2006	2005
Income tax expense from continuing operations at statutory federal income tax rate	**$ 166,824**	$ 149,994	$ 94,632
Increase (decrease) resulting from:			
State income taxes, net of federal income tax benefit	**12,251**	8,906	5,197
Qualified Section 199 production activities deduction	**(8,470)**	(1,114)	(1,060)
401(k) stock dividend deduction	**(637)**	(682)	(667)
Other, net	**(2,539)**	(2,074)	(611)
Total income tax expense from continuing operations	**$ 167,429**	$ 155,030	$ 97,491
Effective income tax rate (%)	**35.13**	36.18	36.06

Total income tax expense for Alagasco differed from the amount which would have been provided by applying the statutory federal income tax rate of 35 percent to earnings before taxes from continuing operations as illustrated below:

Years ended December 31, (in thousands)	**2007**	2006	2005
Income tax expense at statutory federal income tax rate	**$ 20,459**	$ 20,755	$ 20,763
Increase (decrease) resulting from:			
State income taxes, net of federal income tax benefit	**1,643**	1,666	1,673
Other, net	**(466)**	(419)	(76)
Total income tax expense	**$ 21,636**	$ 22,002	$ 22,360
Effective income tax rate (%)	**37.01**	37.10	37.69

Energen adopted the provisions of FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement No. 109 (FIN 48) as of January 1, 2007. This Interpretation prescribed a recognition threshold and measurement attribute for the financial statement recognition, measurement and disclosure of a tax position taken or expected to be taken in a tax return. As a result of the implementation of FIN 48, the Company recognized an approximate $1.2 million increase in the liability for unrecognized tax benefits which was accounted for as a decrease to the January 1, 2007 retained earnings balance. A reconciliation of Energen s beginning and ending amount of unrecognized tax benefits is as follows:

(in thousands)	
Balance as of 1/1/2007	**$ 8,163**
Additions based on tax positions related to the current year	**1,162**
Additions for tax positions of prior years	**2,372**
Reductions for tax positions of prior years (lapse of statute of limitations)	**(3,180)**
Balance as of 12/31/2007	**$ 8,517**

The amount of unrecognized tax benefits at December 31, 2007 that would favorably impact the Company s effective tax rate, if recognized, is $2.5 million. The Company recognizes potential accrued interest and penalties related to unrecognized tax benefits in income tax expense. During the years ended December 31, 2007, 2006, and 2005, the Company recognized approximately $36,000 of expense, $155,000 of income, and $636,000 of expense for interest (net of tax benefit) and penalties, respectively. The Company had approximately $517,000 and $481,000 for the payment of interest (net of tax benefit) and penalties accrued at December 31, 2007, and 2006, respectively. The Company s tax returns for years 2004-2006 remain open to examination by the Internal Revenue Service and major state taxing jurisdictions. The Company recognized approximately $1.8 million of previously unrecognized tax benefits in the current year as the result of the statute of limitations expiring for federal and state tax returns prior to 2004. This change recognized in the current year, which is reflected in the Company s effective tax rate reconciliation as shown above, and the change in the unrecognized tax benefit expected within the next 12 months is not considered material to the financial statements.

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The adoption of FIN 48 resulted in no adjustment to Alagasco s January 1, 2007 retained earnings balance. A reconciliation of Alagasco s beginning and ending amount of unrecognized tax benefits is as follows:

(in thousands)	
Balance as of 1/1/2007	**$ 713**
Additions for tax positions of prior years	**578**
Reductions for tax positions of prior years (lapse of statute of limitations)	**(336)**
Balance as of 12/31/2007	**$ 955**

None of Alagasco s unrecognized tax benefits at December 31, 2007 would impact the Company s effective tax rate, if recognized. The Company recognizes potential accrued interest and penalties related to unrecognized tax benefits in income tax expense. During the years ended December 31, 2007, 2006, and 2005, the Company recognized approximately $23,000 of expense, $36,000 of income, and $100,000 of expense for interest (net of tax benefit) and penalties, respectively. The Company had approximately $87,000 and $64,000 for the payment of interest (net of tax benefit) and penalties accrued at December 31, 2007, and 2006, respectively. The Company s tax returns for years 2004-2006 remain open to examination by the Internal Revenue Service and the state of Alabama. The Company recognized approximately $214,000 of previously unrecognized tax benefits in the current year as the result of the statute of limitations expiring for federal and state tax returns prior to 2004. This change recognized in the current year and the change in the unrecognized tax benefit expected within the next 12 months is not considered material to the financial statements.

5. EMPLOYEE BENEFIT PLANS

In December 2006, the Company adopted SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132 (R) (SFAS No. 158). This Standard retained the previous periodic expense calculation on an actuarial basis under the provisions of SFAS No. 87, Employers Accounting for Pensions and SFAS No. 106, Employers Accounting for Postretirement Benefits Other Than Pensions. In addition, SFAS No. 158 requires an employer to recognize the net funded status of defined benefit pensions and other postretirement benefit plans (benefit plans) as an asset or liability in its statement of financial position and to recognize changes in the funded status through comprehensive income. Additional minimum pension liabilities (AML) and related intangible assets are derecognized upon adoption of the new Standard. For pension plans, the benefit obligation is the projected benefit obligation; for other postretirement plans, the benefit obligation is the accumulated postretirement benefit obligation. Alagasco established a regulatory asset for the portion of the obligation to be recovered in rates in future periods and a liability for the portion of the plan obligation to be provided through rates in the future in accordance with SFAS No. 71. SFAS No. 158 also requires an employer to measure the funded status of a plan as of the date of its year-end statement of financial position effective for fiscal years ending after December 15, 2008. The Company currently uses a September 30 valuation date for its benefit plans and anticipates adopting the change in measurement date using the alternative method. During 2008, the Company expects a reduction to retained earnings of approximately $1.7 million to complete implementation of this Standard.

The following table summarizes the effect of required changes to the Company s financial statements as of December 31, 2006 prior and subsequent to the adoption of SFAS No. 158.

(in thousands)	Prior to SFAS No. 158 Adoption	AML Adjustment	SFAS No. 158 Adjustment	Subsequent to SFAS No. 158 Adoption
Prepaid pension costs	$ 49,500	$ -	$ (43,914)	$ 5,586
Postretirement assets	$ -	$ -	$ 14,389	$ 14,389
Regulatory asset	$ 22,807	$ (22,807)	$ 28,476	$ 28,476
Other assets	$ 3,337	$ (558)	$ (2,781)	$ -
Accumulated other comprehensive income, net of tax	$ 13,707	$ (5,686)	$ 15,156	$ 23,177
Pension liabilities	$ 47,234	$ (32,113)	$ 21,016	$ 36,137
Regulatory liability	$ -	$ -	$ 7,220	$ 7,220

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Pension Plans:

The Company has two defined benefit non-contributory qualified pension plans. These plans cover substantially all employees. Pension benefits for the majority of the Company s employees are based on years of service and final earnings; one plan is based on years of service and flat dollar amounts. The Company s policy is to use the projected unit credit actuarial method for funding and financial reporting purposes. The Company also has nonqualified supplemental pension plans covering certain officers of the Company.

The following table sets forth the combined funded status of the pension plans and their reconciliation with the related amounts in the Company s consolidated financial statements. The effect of changes prior to implementation of SFAS No. 158 as well as the impact upon initial adoption of SFAS No. 158 are reflected below:

(in thousands)	**2007**	2006
Accumulated benefit obligation (September 30)	**$ 161,437**	$ 164,207
Projected benefit obligation:		
Balance at beginning of period	**$ 198,637**	$ 200,977
Service cost	**6,812**	6,452
Interest cost	**11,106**	10,715
Plan amendments	**2,538**	154
Actuarial loss (gain)	**3,614**	(4,525)
Benefits paid	**(23,344)**	(15,136)

Balance at end of period (September 30)	**$**	**199,363**	$	198,637
Plan assets:				
Fair value of plan assets at beginning of period	**$**	**160,936**	$	140,211
Actual return on plan assets		**22,245**		12,937
Employer contributions		**16,807**		22,924
Benefits paid		**(23,344)**		(15,136)
Fair value of plan assets at end of period (September 30)	**$**	**176,644**	$	160,936
Before reflecting SFAS 158:				
Amounts recognized in the consolidated balance sheets:				
Funded status of plan	**$**	**-**	$	(37,701)
Unrecognized actuarial loss		**-**		67,125
Unrecognized prior service cost		**-**		4,330
Employer contributions (October 1 to December 31)		**-**		7,150
Accrued pension asset (December 31)	**$**	**-**	$	40,904
Prepaid benefit cost		**-**		42,500
Accrued benefit liability		**-**		(23,868)
Intangible asset		**-**		2,781
Accumulated other comprehensive income		**-**		12,340
Net amount recognized (September 30)	**$**	**-**	$	33,753
After reflecting SFAS 158:				
Funded status of plan	**$**	**(22,718)**	$	(37,701)
Employer contributions (October 1 to December 31)		**50**		7,150
Net pension liability (December 31)	**$**	**(22,668)**	$	(30,551)
Noncurrent assets	**$**	**12,443**	$	5,586
Current liabilities		**(3,126)**		(3,633)
Noncurrent liabilities		**(31,985)**		(32,504)
Net liability recognized (December 31)	**$**	**(22,668)**	$	(30,551)
Amounts recognized to accumulated other comprehensive income:				
Prior service costs, net of tax of $0.9 million and $1 million	**$**	**1,675**	$	1,877
Net actuarial loss, net of tax of $11.1 million and $12.9 million		**20,525**		23,957
Total accumulated other comprehensive income (December 31)	**$**	**22,200**	$	25,834

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Alagasco recognized a regulatory asset of $21.2 million and $28.5 million as of December 31, 2007 and 2006, respectively, for the portion of the obligation to be recovered through rates in future periods in accordance with SFAS No. 71. Additionally, Alagasco also recognized an offset of $2 million and $3.2 million to a regulatory liability as of December 31, 2007 and 2006, respectively, for the portion of the plan obligation to be provided through rates in future periods in accordance with SFAS No. 71.

Related to the Company s nonqualified supplemental retirement plans, the Company has designated assets of $27.3 million and $26.9 million as of December 31, 2007 and 2006, respectively. While intended for payment of this benefit, these assets remain subject to the claims of the Company s creditors and are not included in the fair value of plan assets in the above table. Accordingly, these assets are not recognized in the funded status of the plan.

Other changes in pension plan assets and projected benefit obligations recognized in other comprehensive income during 2007 were as follows:

(in thousands)

Net actuarial loss experienced during the year	**$**	**1,312**
Net actuarial loss recognized as expense		**(6,583)**
Prior service cost recognized as expense		**(321)**
Total recognized in other comprehensive income (December 31)	**$**	**(5,592)**

Estimated amounts to be amortized from accumulated other comprehensive income into pension cost during 2008 are as follows:

(in thousands)

Amortization of prior service cost	**$ 321**
Amortization of net actuarial loss	**$ 2,706**

Weighted average rate assumptions used to determine the projected benefit obligations at the measurement date:

	September 30, 2007	September 30, 2006
Discount rate	**6.18%**	5.77%
Rate of compensation increase for pay-related plans	**4.07%**	4.22%

The components of net pension expense were:

Years ended December 31, (in thousands)	**2007**	2006	2005
Components of net periodic benefit cost:			
Service cost	**$ 6,812**	$ 6,452	$ 6,400
Interest cost	**11,106**	10,715	10,458
Expected long-term return on assets	**(13,070)**	(11,990)	(10,954)
Transition amortization	**-**	4	5
Prior service cost amortization	**918**	726	916
Actuarial loss	**4,611**	5,257	4,348
Settlement loss	**5,656**	326	-
Net periodic expense	**$ 16,033**	$ 11,490	$ 11,173

Net retirement expense for Alagasco was $6,812,000, $6,158,000 and $6,288,000 for the years ended December 31, 2007, 2006 and 2005, respectively. The Company recognized settlement charges of $2.4 million in 2007 for the payment of lump sums from the nonqualified supplemental retirement plans. The Company also recognized a settlement charge of $3.2 million in the third quarter of 2007 for the payment of lump sums from a defined benefit

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pension plan. This charge represented an acceleration of the unamortized actuarial losses as required under SFAS No. 88, Employers Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits.

Weighted average rate assumptions to determine net periodic benefit costs for the period ending:

	December 31, 2007	December 31, 2006	December 31, 2005
Discount rate	**5.77%**	5.50%	5.75%
Expected long-term return on plan assets	**8.25%**	8.50%	8.50%
Rate of compensation increase for pay-related plans	**4.22%**	3.60%	4.00%

The Company s weighted-average defined benefit pension plan asset allocations by asset category were as follows:

	Target	**December 31, 2007**	**December 31, 2006**
Asset category:			
Equity securities	**56%**	**51%**	53%
Debt securities	**32%**	**29%**	31%
Other	**12%**	**20%**	16%
Total	**100%**	**100%**	100%

Plan equity securities do not include the Company s common stock. The Company is not required to make pension contributions in 2008 and does not currently plan on making discretionary contributions. The Company expects to make benefit payments of approximately $3.1 million during 2008 to retirees from the nonqualified supplemental retirement plans.

Defined benefit pension plan payments, which reflect expected future service, are anticipated to be paid as follows:

(in thousands)	
2008	**$ 16,672**
2009	**$ 14,156**
2010	**$ 14,231**
2011	**$ 14,722**
2012	**$ 15,169**
2013-2017	**$ 89,194**

Postretirement Health Care and Life Insurance Benefits:

In addition to providing pension benefits, the Company provides certain postretirement health care and life insurance benefits. Substantially all of the Company s employees may become eligible for certain benefits if they reach normal retirement age while working for the Company. The projected unit credit actuarial method was used to determine the normal cost and actuarial liability.

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The status of the postretirement benefit programs was as follows:

(in thousands)	**2007**	2006
Projected postretirement benefit obligation:		
Balance at beginning of period	**$ 63,818**	$ 70,229
Service cost	**1,022**	1,217
Interest cost	**3,693**	3,682
Actuarial (gain) loss	**14,395**	(7,758)
Benefits paid	**(3,953)**	(3,552)
Balance at end of period (September 30)	**$ 78,975**	$ 63,818
Plan assets:		
Fair value of plan assets at beginning of period	**$ 77,939**	$ 73,552
Actual return on plan assets	**11,493**	6,387
Employer contributions	**1,181**	1,552
Benefits paid	**(3,953)**	(3,552)
Fair value of plan assets at end of period (September 30)	**$ 86,660**	$ 77,939
Before reflecting SFAS 158:		
Amounts recognized in the consolidated balance sheets:		
Funded status of plan	**$ -**	$ 14,121
Unrecognized actuarial gain	**-**	(27,949)
Unrecognized net transition obligation	**-**	13,409
Employer contributions (October 1 to December 31)	**-**	268
Accrued benefit liability (December 31)	**$ -**	$ (151)
After reflecting SFAS 158:		
Funded status of plan	**$ 7,685**	$ 14,121
Employer contributions (October 1 to December 31)	**234**	268
Net pension asset (December 31)	**$ 7,919**	$ 14,389
Noncurrent assets	**$ 7,919**	$ 14,389
Net asset recognized (December 31)	**$ 7,919**	$ 14,389
Amounts recognized to accumulated other comprehensive income (loss):		
Transition obligation, net of taxes of $585 and $640	**$ 1,086**	$ 1,188

Net actuarial gain, net of taxes of ($1,141) and ($2,070)	**(2,119)**	(3,845)
Total accumulated other comprehensive loss (December 31)	**$ (1,033)**	$ (2,657)

Alagasco recognized a regulatory liability of $6.2 million and $10.5 million as of December 31, 2007 and 2006, respectively. This amount will reduce recovery rates in future periods in accordance with SFAS No. 71.

Other changes in postretirement plan assets and projected benefit obligations recognized in other comprehensive income during 2007 were as follows:

(in thousands)	
Net actuarial loss experienced during the year	**$ 2,464**
Amortization of net actuarial gain	**279**
Amortization of transition obligation	**(246)**
Total recognized in other comprehensive loss (December 31)	**$ 2,497**

Estimated amounts to be amortized from accumulated other comprehensive income into benefit cost during 2008 are as follows:

(in thousands)	
Amortization of transition obligation	**$ 259**
Amortization of net actuarial gain	**$ (120)**

Weighted average rate assumptions used to determine postretirement benefit obligations at the measurement date:

	September 30, 2007	September 30, 2006
Discount rate	**6.40%**	5.95%
Rate of compensation increase for pay-related plans	**3.65%**	3.70%

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Net periodic postretirement benefit expense included the following:

Years ended December 31, (in thousands)	**2007**	2006	2005
Components of net periodic benefit cost:			
Service cost	**$ 1,023**	$ 1,217	$ 1,423
Interest cost	**3,693**	3,682	4,030
Expected long-term return on assets	**(5,002)**	(4,858)	(4,335)
Actuarial gain	**(1,260)**	(884)	(274)
Prior service costs			4
Transition amortization	**1,917**	1,917	1,967
Net periodic expense	**$ 371**	$ 1,074	$ 2,815

Net periodic postretirement benefit expense for Alagasco was $300,000, $971,000 and $2,273,000 for the years ended December 31, 2007, 2006 and 2005, respectively.

Weighted average rate assumptions to determine net periodic benefit costs for the years ending:

	December 31, 2007	December 31, 2006	December 31, 2005
Discount rate	**5.95%**	5.50%	5.75%
Expected long-term return on plan assets	**8.25%**	8.50%	8.50%

Rate of compensation increase	**3.70%**	3.50%	4.00%

Assumed post-65 health care cost trend rates used to determine the postretirement benefit obligation at the measurement date:

	September 30, 2007	September 30, 2006
Health care cost trend rate assumed for next year	**9.50%**	10.00%
Rate to which the cost trend rate is assumed to decline	**5.50%**	5.00%
Year that rate reaches ultimate rate	**2011**	2011

Assumed health care cost trend rates used in determining the accumulated postretirement benefit obligation have an effect on the amounts reported. For example, increasing the weighted average health care cost trend rate by 1 percentage point would have the following effects:

(in thousands)	**1-Percentage Point Increase**
Effect on total of service and interest cost	**$ 306**
Effect on net postretirement benefit obligation	**$ 4,916**

The Company s weighted-average postretirement benefit program asset allocations by asset category were as follows:

	Target	**December 31, 2007**	December 31, 2006
Asset category:			
Equity securities	**70%**	**70%**	71%
Debt securities	**30%**	**30%**	20%
Other	**0%**	**0%**	9%
Total	**100%**	**100%**	100%

Equity securities for the postretirement benefit programs do not include the Company s common stock. The Company expects to make discretionary contributions of $2.2 million to postretirement benefit program assets during 2008.

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The following postretirement benefit payments, which reflect expected future service, are anticipated to be paid:

(in thousands)	
2008	**$ 4,867**
2009	**$ 5,088**
2010	**$ 5,303**
2011	**$ 5,519**
2012	**$ 5,689**
2013-2017	**$ 30,277**

The following benefits reflect the expected prescription drug subsidy related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Act). The Act includes a prescription drug benefit under Medicare Part D as well as a federal subsidy beginning in 2007:

(in thousands)	
2008	**$ (363)**
2009	**$ (382)**
2010	**$ (393)**

2011	**$**	**(401)**
2012	**$**	**(405)**
2013-2017	**$**	**(1,958)**

For retirement plans and other postretirement plans, certain financial assumptions are used in determining the Company s projected benefit obligation. These assumptions are examined periodically by the Company, and any required changes are reflected in the subsequent determination of projected benefit obligations.

The Company employs a total return investment approach whereby a mix of equities and fixed income investments are used to maximize the long-term return of plan assets with a prudent level of risk. Risk tolerance is established through consideration of plan liabilities, plan funded status, corporate financial condition, and market conditions.

The Company has developed an investment strategy that focuses on asset allocation, diversification and quality guidelines. The investment goals of the Company are to obtain an adequate level of return to meet future obligations of the plan by providing above average risk-adjusted returns with a risk exposure in the mid-range of comparable funds. Investment managers are retained by the Company to manage separate pools of assets. Funds are allocated to such managers in order to achieve an appropriate, diversified, and balanced asset mix. Comparative market and peer group benchmarks are utilized to ensure that investment managers are performing satisfactorily.

The Company based its expected return on long-term investment expectations. The Company considered past performance and current expectations for assets held by the plan as well as the expected long-term allocation of plan assets. At December 31, 2007, the expected return on plan assets was 8.25%.

The Company has a long-term disability plan covering most employees. The Company had expense for the years ended December 31, 2007, 2006 and 2005 of $382,000, $304,000 and $438,000, respectively.

6. COMMON STOCK PLANS

Energen Employee Savings Plan (ESP): A majority of Company employees are eligible to participate in the ESP by electing to contribute a portion of their compensation to the ESP. The Company may match a percentage of the contributions and make these contributions in Company common stock (new issue or treasury shares) or in funds for the purchase of Company common stock. Vested employees may diversify 100 percent of their ESP Company stock account into other ESP investment options. The ESP also contains employee stock ownership plan provisions. At December 31, 2007, total shares reserved for issuance equaled 1,080,108. Expense associated with Company contributions to the ESP was $5,237,000, $4,891,000 and $4,650,000 for the years ended December 31, 2007, 2006 and 2005, respectively.

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1997 Stock Incentive Plan and 1988 Stock Option Plan: The 1997 Stock Incentive Plan and the Energen 1988 Stock Option Plan provided for the grant of incentive stock options and non-qualified stock options to officers and key employees. The 1997 Stock Incentive Plan also provided for the grant of performance share awards and restricted stock. Under the 1997 Stock Incentive Plan, 5,600,000 shares of Company common stock were reserved for issuance with 1,740,054 remaining for issuance as of December 31, 2007. Under the 1988 Stock Option Plan, 1,080,000 shares of Company common stock reserved for issuance have been granted.

Performance Share Awards: The Energen 1997 Stock Incentive Plan provided for the grant of performance share awards, with each unit equal to the market value of one share of common stock, to eligible employees based on predetermined Company performance criteria at the end of a four-year award period. On January 25, 2006, the Company amended its 1997 Stock Incentive Plan to provide that payment of earned performance share awards be made in the form of Company common stock, with no portion of an award paid in cash. This amendment affected 29 participants. Prior to the amendment, payment of performance awards could be made in cash or in a combination of Company common stock or cash. The impact of this modification was not significant to the Company.

1997 Stock Incentive Plan performance share awards granted or modified after the adoption of SFAS No. 123R have been valued in a Monte Carlo model. The Monte Carlo model uses historical volatility and other variables to estimate the probability of satisfying the market condition of the award. For performance share awards granted prior to the adoption of SFAS No. 123R, the Company estimated fair value based on the quoted market price of the Company s common stock and adjusted each period for the expected payout ratio.

No performance share awards were granted in 2007. A summary of performance share award activity as of December 31, 2007, and transactions during the years ended December 31, 2007, 2006 and 2005 are presented below:

	1997 Stock Incentive Plan	
		Weighted
	Shares	Average Price
Nonvested at December 31, 2004	574,820	$ 38.18
Granted	117,540	29.16
Paid	(214,640)	51.80
Nonvested at December 31, 2005	477,720	40.26
Granted	111,990	43.81
Forfeitures	(847)	43.81
Nonvested at December 31, 2006	588,863	40.81
Paid	(225,960)	30.53
Nonvested at December 31, 2007	362,903	$ 49.87

The Company recorded expense of $4,254,000, $8,779,000 and $9,338,000 for the years ended December 31, 2007, 2006 and 2005, respectively, for performance share awards with a related deferred income tax benefit of $1,608,000, $3,319,000 and $3,531,000, respectively. As of December 31, 2007, there was $1,963,000 of total unrecognized compensation cost related to performance share awards. These awards have a weighted average requisite service period of 1.27 years from the date of grant.

Stock Options: The 1997 Stock Incentive Plan and the Energen 1988 Stock Option Plan provided for the grant of incentive stock options, non-qualified stock options, or a combination thereof to officers and key employees. Options granted under the Plans provide for the purchase of Company common stock at not less than the fair market value on the date the option is granted. The sale or transfer of the shares is limited during certain periods. All outstanding options are incentive or non-qualified, vest within three years from date of grant, and expire 10 years from the grant date.

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A summary of stock option activity as of December 31, 2007, and transactions during the years ended December 31, 2007, 2006 and 2005 are presented below:

	1997 Stock Incentive Plan		1988 Stock Option Plan	
		Weighted Average		Weighted Average
	Shares	Exercise Price	Shares	Exercise Price
Outstanding at December 31, 2004	695,240	$ 13.72	58,000	$ 7.39
Exercised	(80,140)	11.26	(30,000)	5.77
Forfeited	(1,700)	14.86	-	-
Outstanding at December 31, 2005	613,400	14.04	28,000	9.13
Exercised	(206,322)	13.18	(7,000)	9.13
Outstanding at December 31, 2006	407,078	14.69	21,000	9.13
Granted	239,545	46.71	-	-
Exercised	(180,284)	15.59	(21,000)	9.13
Outstanding at December 31, 2007	466,339	$ 30.79	-	$ -
Exercisable at December 31, 2005	415,260	$ 10.48	28,000	$ 9.13
Exercisable at December 31, 2006	324,318	$ 12.98	21,000	$ 9.13
Exercisable at December 31, 2007	226,794	$ 13.97	-	$ -
Remaining reserved for issuance at December 31, 2007	1,740,054	-	-	-

The Company granted options for 232,285 shares during the first quarter of 2007 and 7,260 shares during the second quarter of 2007 with weighted-average grant-date fair values of $17.33 and $20.05, respectively. The Company uses the Black-Scholes pricing model to calculate the fair values of the options awarded. For purposes of this valuation the following assumptions were used to derive the fair values: a 6 year time of exercise; an annualized volatility rate of 27.3 percent and 25.2 percent for the first and second quarters of 2007, respectively; a risk-free interest rate of 4.75 percent and 5 percent for the first and second quarters of 2007, respectively; and a dividend yield of zero to reflect dividend protection in award provisions. The Company granted no stock options during 2006 and 2005. The Company recorded stock option expense of $3,124,000, $196,000 and $465,000 during the years ended December 31, 2007, 2006 and 2005, respectively, with a related deferred tax benefit of $1,181,000, $41,000 and $107,000 respectively.

The total intrinsic value of stock options exercised during the year ended December 31, 2007, was $7,161,000. During the year ended December 31, 2007, the total intrinsic value of stock appreciation rights exercised was $1,095,000. During the year ended December 31, 2007, the Company received cash of $3,908,000 from the exercise of stock options and paid $608,000 in settlement of stock appreciation rights. Total intrinsic value for outstanding options as of December 31, 2007, was $15,664,000 and $11,468,000 for exercisable options. The fair value of options vested for the year ended December 31, 2007 was $588,000. As of December 31, 2007, there was $1,038,000 of unrecognized compensation cost related to outstanding nonvested stock options.

The following table summarizes options outstanding as of December 31, 2007:

1997 Stock Incentive Plan

Range of Exercise Prices	Shares	Weighted Average Remaining Contractual Life
$9.13-$9.41	34,102	1.43 years
$13.72	57,250	2.83 years
$11.32	37,880	3.83 years
$14.86	69,080	5.08 years
$21.38	28,482	6.08 years
$46.45	232,285	9.00 years
$55.08	7,260	9.50 years
$9.13-$55.08	466,339	6.52 years

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The weighted average remaining contractual life of currently exercisable stock options is 3.88 years as of December 31, 2007.

Restricted Stock: In addition, the 1997 Stock Incentive Plan provided for the grant of restricted stock which have been valued based on the quoted market price of the Company s common stock at the date of grant. A summary of restricted stock activity as of December 31, 2007, and transactions during the years ended December 31, 2007, 2006 and 2005 is presented below:

	1997 Stock Incentive Plan	
	Shares	Weighted Average Price
Nonvested at December 31, 2004	221,028	$ 18.99
Granted	44,040	29.16
Vested	(21,424)	22.46
Forfeited	(1,200)	29.16
Nonvested at December 31, 2005	242,444	20.48
Granted	44,750	40.10
Vested	(59,764)	14.99
Forfeited	(1,600)	29.16
Nonvested at December 31, 2006	225,830	25.76
Granted	6,805	46.45
Vested	(95,040)	21.18
Nonvested at December 31, 2007	137,595	$ 29.94

The Company recorded expense of $908,000, $2,252,000 and $1,800,000 for the years ended December 31, 2007, 2006 and 2005, respectively, related to restricted stock, with a related deferred income tax benefit of $343,000, $851,000 and $681,000, respectively. As of December 31, 2007, there was $1,092,000 of total unrecognized compensation cost related to nonvested restricted stock awards recorded in premium on capital stock. These awards have a requisite service period of 1.19 years from the date of grant. The Company has typically funded options, restricted stock obligations and performance share obligations through original issue shares.

2004 Stock Appreciation Rights Plan: The Energen 2004 Stock Appreciation Rights Plan provided for the payment of cash incentives measured by the long-term appreciation of Company stock. These awards are liability awards which settle in cash and are re-measured each reporting period until settlement. These awards have a three year requisite service period. Awards granted prior to January 1, 2006 were valued using the intrinsic value method. During 2007, 85,906 awards were granted with stock appreciation rights. These awards had a weighted average grant-date fair value of $26.79 as of December 31, 2007 which was calculated using the Black-Scholes pricing model. For purposes of this valuation the following assumptions were used to derive the fair value: an expected life of the award of 5.6 years; an annualized volatility rate of 24.2 percent; a risk-free interest rate of 3.58 percent; and a dividend yield of 0.7 percent. There were no awards granted with stock appreciation rights in 2006 or 2005. Expense associated with stock appreciation rights of $1,933,000, $1,218,000 and $1,326,000 was recorded for the years ended December 31, 2007, 2006 and 2005, respectively.

2005 Petrotech Incentive Plan: The Energen Resources 2005 Petrotech Incentive Plan provided for the grant of stock equivalent units which may include market conditions. These awards are liability awards which settle in cash and are re-measured each reporting period until settlement and have a three year vesting period. Effective January 1, 2006, the fair value of the stock equivalent units with a market condition was calculated using a Monte Carlo approach. Stock equivalent units with service conditions were valued based on the Company s stock price at the end of the period adjusted to remove the present value of future dividends. Prior to the implementation of SFAS No. 123R, these awards were valued using the Company s common stock price at each period end.

During 2007, Energen Resources awarded 5,242 stock equivalent units none of which included a market condition. During 2006, Energen Resources awarded 25,720 stock equivalent units of which 22,545 included a market condition. Energen Resources awarded 46,920 stock equivalent units in 2005 of which 23,460 included a market condition. Energen Resources recognized expense of $2,389,000, $791,000 and $534,000 during 2007, 2006 and 2005, respectively, related to these units.

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1997 Deferred Compensation Plan: The 1997 Deferred Compensation Plan allowed officers and non-employee directors to defer certain compensation. Amounts deferred by a participant under the 1997 Deferred Compensation Plan are credited to accounts maintained for a participant in either a stock account or an investment account. The stock account tracks the performance of the Company s common stock, including reinvestment of dividends. The investment account tracks the performance of certain mutual funds. The Company has funded, and presently plans to continue funding, a trust in a manner that generally tracks participants accounts under the 1997 Deferred Compensation Plan. While intended for payment of benefits under the 1997 Deferred Compensation Plan, the trust s assets remain subject to the claims of the Company s creditors. Amounts earned under the Deferred Compensation Plan and invested in Company common stock held by the trust have been recorded as treasury stock, along with the related deferred compensation obligation in the Consolidated Statements of Shareholders Equity.

Shareholder Rights Plan: On June 24, 1998, the Company adopted a Shareholder Rights Plan (the 1998 Plan) designed to protect shareholders from coercive or unfair takeover tactics. Under certain circumstances, the 1998 Plan provides shareholders with the right to acquire the Company s Series 1998 Junior Participating Preferred Stock (or, in certain cases, securities of an acquiring person) at a significant discount. Terms and conditions are set forth in a Rights Agreement between the Company and its Rights Agent. Under the 1998 Plan, one half of a right is associated with each outstanding share of common stock. Rights outstanding under the 1998 Plan at December 31, 2007, were convertible into 741,908 shares of Series 1998 Junior Participating Preferred Stock (1/100 share of preferred stock for each full right) subject to adjustment upon occurrence of certain take-over related events. No rights were exercised or exercisable during the period. The price at which the rights would be exercised is $70 per right, subject to adjustment upon occurrence of certain take-over related events. In general, absent certain take-over related events as described in the Plan, the rights may be redeemed prior to the July 27, 2008 expiration for $0.01 per right.

1992 Energen Corporation Directors Stock Plan: In 1992 the Company adopted the Energen Corporation 1992 Directors Stock Plan to pay part of the compensation of its non-employee directors in shares of Company common stock. Under the Plan, 11,503 shares, 11,517 shares and 12,116 shares were awarded during the years ended December 31, 2007, 2006 and 2005, respectively, leaving 213,942 shares reserved for issuance as of December 31, 2007.

Dividend Reinvestment and Direct Stock Purchase Plan: The Company s Dividend Reinvestment and Direct Stock Purchase Plan included a direct stock purchase feature which allowed purchases by non-shareholders. As of December 31, 2007, 1,098,292 common shares were reserved under this Plan. Effective December 15, 2006, the Company suspended operations under the Plan and shareholders became eligible to reinvest dividends or make direct stock purchases using the Company s stock transfer and dividend paying agent, The Bank of New York.

By resolution adopted May 25, 1994, and supplemented by a resolution adopted April 26, 2000 and June 24, 2006, the Board authorized the Company to repurchase up to 12,564,400 shares of the Company s common stock. There were no shares repurchased pursuant to its repurchase authorization for the years ended December 31, 2007 and 2005. For the year ended December 31, 2006, the Company repurchased 2,158,000 shares pursuant to its repurchase authorization. As of December 31, 2007, a total of 8,992,700 shares remain authorized for future repurchase. The Company also from time to time acquires shares in connection with participant elections under the Company s stock compensation plans. For the years ended December 31, 2007, 2006 and 2005, the Company acquired 209,388 shares, 82,707 shares and 67,957 shares, respectively, in connection with its stock compensation plans.

7. COMMITMENTS AND CONTINGENCIES

Commitments and Agreements: Certain of Alagasco s long-term gas procurement contracts for the supply, storage and delivery of natural gas include fixed charges of approximately $178 million through October 2015. Alagasco also is committed to purchase minimum quantities of gas at market-related prices or to pay certain costs in the event the minimum quantities are not taken. These purchase commitments are approximately 135.2 Bcf through April 2015.

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Environmental Matters: Various environmental laws and regulations apply to the operations of Energen Resources and Alagasco. Historically, the cost of environmental compliance has not materially affected the Company s financial position, results of operations or cash flows and is not expected to do so in the future; however, new regulations, enforcement policies, claims for damages or other events could result in significant unanticipated costs.

A discussion of certain litigation in the state of Louisiana related to the restoration of oilfield properties is included below under Legal Matters.

Alagasco is in the chain of title of nine former manufactured gas plant sites (four of which it still owns), and five manufactured gas distribution sites (one of which it still owns). An investigation of the sites does not indicate the present need for remediation activities. Management expects that, should remediation of any such sites be required in the future, Alagasco s share, if any, of such costs will not materially affect the financial position of Alagasco.

Legal Matters: Energen and its affiliates are, from time to time, parties to various pending or threatened legal proceedings. Certain of these lawsuits include claims for punitive damages in addition to other specified relief. Based upon information presently available, and in light of available legal and other defenses, contingent liabilities arising from threatened and pending litigation are not considered material in relation to the respective financial positions of Energen and its affiliates. It should be noted, however, that Energen and its affiliates conduct business in jurisdictions in which the magnitude and frequency of punitive and other damage awards may bear little or no relation to culpability or actual damages, thus making it difficult to predict litigation results.

Jefferson County, Alabama

In January 2006, RGGS Land and Minerals LTD, L.P. (RGGS) filed a lawsuit in Jefferson County, Alabama, alleging breach of contract with respect to Energen Resources calculation of certain allowed costs and failure to pay in a timely manner certain amounts due RGGS under a mineral lease. RGGS seeks a declaratory judgment with respect to the parties rights under the lease, reformation of the lease, monetary damages and termination of Energen Resources rights under the lease. The Occluded Gas Lease dated January 1, 1986 was originally between Energen Resources and United States Steel Corporation (U.S. Steel) as lessor. RGGS became the lessor under the lease as a result of a 2004 conveyance from U.S. Steel to RGGS. Approximately 120,000 acres in Jefferson and Tuscaloosa counties, Alabama, are subject to the lease. Separately on February 6, 2006, Energen Resources received notice of immediate lease termination from RGGS. During 2007, Energen Resources production associated with the lease was approximately 10.5 Bcf.

RGGS has adopted positions contrary to the seventeen years of course of dealing between Energen Resources and its original contracting partner, U.S. Steel. The Company believes that RGGS assertions are without merit and that the notice of lease termination is ineffective. Energen Resources intends to vigorously defend its rights under the lease. The Company remains in possession of the lease, believes that the likelihood of a judgment in favor of RGGS is remote, and has made no material accrual with respect to the litigation or purported lease termination.

Enron Corporation

During 2006, Enron and Enron North America Corporation (ENA) settled with Energen Resources and Alagasco related to the Enron and ENA bankruptcy proceedings. Under the settlement, Energen Resources was allowed claims in the bankruptcy cases against Enron and ENA of $12.5 million each. In December 2006, Energen Resources sold its claims against Enron and ENA for a gain of $6.7 million after-tax. All other claims have been released.

Legacy Litigation

During recent years, numerous lawsuits have been filed against oil production companies in Louisiana for restoration of oilfield properties. These suits are referred to in the industry as legacy litigation because they usually involve operations that were conducted on the affected properties many years earlier. Energen Resources is or has been a party to several legacy litigation lawsuits, most of which result from the operations of predecessor companies. Based upon information presently available, and in light of available legal and other defenses, contingent liabilities arising from legacy litigation in excess of the Company s accrued provision for estimated liability are not considered material to the Company s financial position.

Other

Various other pending or threatened legal proceedings are in progress currently, and the Company has accrued a provision for estimated liability.

Lease Obligations: Alagasco leases the Company s headquarters building over a 25-year term and the related lease is accounted for as an operating lease. Under the terms of the lease, Alagasco has a renewal option; the lease does not contain a bargain purchase price or a residual value guarantee. Energen s total lease payments related to leases included as operating lease expense were $18,212,000, $15,845,000 and $13,628,000 for the years ended December 31, 2007, 2006 and 2005, respectively. Minimum future rental payments required after 2007 under leases with initial or remaining noncancelable lease terms in excess of one year are as follows:

Years Ending December 31, *(in thousands)*					
2008	**2009**	**2010**	**2011**	**2012**	**2013 and thereafter**
$ 4,128	$ 4,258	$ 3,834	$ 3,661	$ 3,678	$ 26,588

Alagasco s total payments related to leases included as operating expense were $3,180,000, $3,310,000 and $3,148,000 for the years ended December 31, 2007, 2006 and 2005, respectively. Minimum future rental payments required after 2007 under leases with initial or remaining noncancelable lease terms in excess of one year are as follows:

Years Ending December 31, *(in thousands)*					
2008	**2009**	**2010**	**2011**	**2012**	**2013 and thereafter**
$ 3,139	$ 3,147	$ 3,113	$ 3,121	$ 3,137	$ 26,452

8. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Financial Instruments: The stated value of cash and cash equivalents, trade receivables (net of allowance), and short-term debt approximates fair value due to the short maturity of the instruments. The fair value of Energen s long-term debt, including the current portion, with a carrying value of $573,467,000 would be $595,146,000 at December 31, 2007. The fair value of Alagasco s fixed-rate long-term debt, including the current portion, with a carrying value of $208,467,000 would be $203,237,000 at December 31, 2007. The fair values were based on current market prices.

Alagasco purchases gas as an agent for certain of its large commercial and industrial customers. Alagasco has in certain instances provided commodity-related guarantees to counterparties in order to facilitate these agency purchases. Liabilities existing for gas delivered to customers subject to these guarantees are included in the consolidated balance sheet. In the event the customer for whom the guarantee was entered fails to take delivery of the gas, Alagasco can sell such gas for the customer, with the customer liable for any resulting loss. Although the substantial majority of purchases under these guarantees are for the customers current monthly consumption and are at current market prices, in some instances, the purchases are for an extended term at a fixed price. At December 31, 2007, the fixed price purchased under these guarantees had a maximum term outstanding through December 2008 with an aggregate purchase price of $9.3 million and a market value of $8.8 million.

Price Risk: The Company applies SFAS No. 133 as amended which requires all derivatives to be recognized on the balance sheet and measured at fair value. If a derivative is designated as a cash flow hedge, the effectiveness of the hedge, or the degree that the gain (loss) for the hedging instrument offsets the loss (gain) on the hedged item, is measured at each reporting period. The effective portion of the gain or loss on the derivative instrument is recognized in other comprehensive income as a component of equity and subsequently reclassified into earnings in operating revenues when the forecasted transaction affects earnings. The ineffective portion of a derivative s change in fair value is required to be recognized in operating revenues immediately. Derivatives that do not qualify for hedge treatment under SFAS No. 133 must be recorded at fair value with gains or losses recognized in operating revenues in the period of change.

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Energen Resources periodically enters into cash flow derivative commodity instruments to hedge its price exposure on its estimated oil, natural gas and natural gas liquids production. In addition, Alagasco periodically enters into cash flow derivative commodity instruments to hedge its exposure to price fluctuations on its gas supply. Such instruments may include regulated natural gas and crude oil futures contracts traded on the New York Mercantile Exchange and over-the-counter swaps, collars and basis hedges with major energy derivative product specialists. The counterparties to the commodity instruments are investment banks and energy-trading firms. In some contracts, the amount of credit allowed before Energen Resources or Alagasco collateral must be posted for out-of-the-money hedges varies depending on the credit rating of the Company or Alagasco. At December 31, 2007, the counterparty agreements under which the Company had active positions did not include collateral posting requirements. Energen Resources was in a net gain position with three of its counterparties and a net loss with the remaining four. The Company believes the creditworthiness of these counterparties is satisfactory. The three largest counterparties represented approximately 54 percent, 28 percent and 13 percent of Energen Resources loss on fair value of derivatives.

As of December 31, 2007, $37.4 million of deferred net losses on derivative instruments recorded in accumulated other comprehensive income, net of tax, are expected to be reclassified and reported in earnings as operating revenues during the next twelve-month period. The actual amount that will be reclassified to earnings over the next year could vary materially from this amount due to changes in market conditions. Gains and losses on derivative instruments that are not accounted for as cash flow hedge transactions, as well as the ineffective portion of the change in fair value of derivatives accounted for as cash flow hedges, are included in operating revenues in the consolidated financial statements. The Company recorded a $0.7 million after-tax gain in 2007 for the ineffective portion of the change in fair value of derivatives accounted for as cash flow hedges. Also, the Company recorded an after-tax gain of $0.2 million in 2007 on contracts which did not meet the definition of cash flow hedges under SFAS No. 133. As of December 31, 2007, all of the Company s hedges met the definition of a cash flow hedge. During 2007, the Company discontinued hedge accounting and reclassified gains of $0.2 million after-tax from OCI into operating revenues when Energen Resources determined it was probable certain forecasted volumes would not occur.

The Company had $39.9 million and $31 million included in current and noncurrent deferred income taxes on the consolidated balance sheets related to items included in other comprehensive income as of December 31, 2007 and 2006, respectively. The Company had $14 million and $93.3 million of current gains recorded in accounts receivable at December 31, 2007 and 2006 respectively. At December 31, 2007 and 2006, the Company also had $79.9 million and $0.7 million, respectively, of current losses recorded in accounts payable. The Company also had $47.1 million and $11.9 million at December 31, 2007 and 2006, respectively, of non-current losses recorded in deferred credits and other liabilities related to derivative contracts. Additionally, the Company had $2.4 million of non-current gains recorded in deferred charges and other on the consolidated balance sheets as of December 31, 2007.

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As of December 31, 2007, Energen Resources entered into the following transactions for 2008 and subsequent years:

Production Period	Total Hedged Volumes	Average Contract Price	Description
Natural Gas			
2008	30.8 Bcf	$8.53 Mcf	NYMEX Swaps
	18.8 Bcf	$7.53 Mcf	Basin Specific Swaps
2009	24.7 Bcf	$7.81 Mcf	Basin Specific Swaps
Natural Gas Basis Differential			
2008	12.0 Bcf	*	Basis Swaps
Oil			
2008	3,203 MBbl	$70.17 Bbl	NYMEX Swaps
2009	2,460 MBbl	$71.03 Bbl	NYMEX Swaps
2010	720 MBbl	$81.20 Bbl	NYMEX Swaps
Oil Basis Differential			
2008	2,483 MBbl	*	Basis Swaps
2009	1,980 MBbl	*	Basis Swaps
Natural Gas Liquids			
2008	47.8 MMGal	$0.96 Gal	Liquids Swaps
2009	20.2 MMGal	$1.05 Gal	Liquids Swaps

* Average contract prices not meaningful due to the varying nature of each contract

All hedge transactions are subject to the Company s risk management policy, approved by the Board of Directors, which does not permit speculative positions. The Company formally documents all relationships between hedging instruments and hedged items at the inception of the hedge, as well as its risk management objective and strategy for undertaking the hedge. This process includes specific identification of the hedging instrument and the hedge transaction, the nature of the risk being hedged and how the hedging instrument s effectiveness in hedging the exposure to the hedged transaction s variability in cash flows attributable to the hedged risk will be assessed and measured. Both at the inception of the hedge and on an ongoing basis, the Company assesses whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items. The Company discontinues hedge accounting if a derivative has ceased to be a highly effective hedge. The maximum term over which Energen Resources has hedged exposures to the variability of cash flows is through December 31, 2010.

At December 31, 2007, Alagasco recorded a $0.4 million loss as a liability in accounts payable with a corresponding current regulatory asset representing the fair value of derivatives. At December 31, 2006, Alagasco recorded an $11.5 million loss as a liability in accounts payable with a corresponding current regulatory asset representing the fair value of derivatives. Additionally, as of December 31, 2006, Alagasco recorded a current regulatory liability and a corresponding receivable of $1.2 million related to certain interest rate treasury futures. These futures were entered into by the Company to reduce the interest rate risk associated with a $45 million debt issuance completed by Alagasco in January 2007.

Concentration of Credit Risk: Revenues and related accounts receivable from oil and gas operations primarily are generated from the sale of produced natural gas and oil to natural gas and oil marketing companies. Such sales are typically made on an unsecured credit basis with payment due the month following delivery. This concentration of sales to the energy marketing industry has the potential to affect the Company s overall exposure to credit risk, either positively or negatively, in that the Company s oil and gas purchasers may be affected similarly by changes in economic, industry or other conditions. Energen Resources considers the credit quality for its customers and, in certain instances, may require credit assurances such as a deposit, letter of credit or parent guarantee. The two largest oil and gas purchasers accounted for approximately 35 percent and 17 percent of Energen Resources accounts receivable for commodity sales as of December 31, 2007. Energen Resources other purchasers each accounted for less than 9 percent of this accounts receivable as of December 31, 2007. During the year ended December 31, 2007, one purchaser accounted for approximately 15 percent of the Company s total operating revenues.

Natural gas distribution operating revenues and related accounts receivable are generated from state-regulated utility natural gas sales and transportation to approximately 451,000 residential, commercial and industrial customers located in central and north Alabama. A change in economic conditions may affect the ability of customers to meet their obligations; however, the Company believes that its provision for possible losses on uncollectible accounts receivable is adequate for its credit loss exposure.

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9. RECONCILIATION OF EARNINGS PER SHARE (EPS)

Years ended December 31, *(in thousands, except per share amounts)*	**2007**			2006			2005		
	Net Income	**Shares**	**Per Share Amount**	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount
Basic EPS	**$ 309,233**	**71,592**	**$ 4.32**	$ 273,570	72,505	$ 3.77	$ 173,012	73,052	$ 2.37
Effect of dilutive securities									
Performance share awards		**351**			408			208	
Stock options		**158**			252			334	
Non-vested restricted stock		**80**			113			121	
Diluted EPS	**$ 309,233**	**72,181**	**$ 4.28**	$ 273,570	73,278	$ 3.73	$ 173,012	73,715	$ 2.35

For the year ended December 31, 2007, the Company had 239,545 options that were excluded from the computation of diluted EPS, as their effect was non-dilutive. The Company had no options that were excluded from the computation of diluted EPS for years ended December 31, 2006 and 2005. For the years ended December 31, 2007, 2006 and 2005, the Company had no shares of non-vested restricted stock that were excluded from the computation of diluted EPS.

10. ASSET RETIREMENT OBLIGATIONS

The Company applies SFAS No. 143, Accounting for Asset Retirement Obligations, which requires the Company to record the fair value of a liability for an asset retirement obligation (ARO) in the period in which it is incurred. Subsequent to initial measurement, liabilities are required to be accreted to their present value each period and capitalized costs are depreciated over the estimated useful life of the related assets. Upon settlement of the liability, the Company may recognize a gain or loss for differences between estimated and actual settlement costs.

In 2007, 2006 and 2005, Energen Resources recognized amounts representing expected future costs associated with site reclamation, facilities dismantlement, and plug and abandonment of wells as follows:

(in thousands)	
Balance of ARO as of December 31, 2004	$ 34,841
Liabilities incurred during the year ended December 31, 2005	10,102
Liabilities settled during the year ended December 31, 2005	(689)
Revision in estimated cash flows	3,369
Accretion expense	2,647
Balance of ARO as of December 31, 2005	50,270
Liabilities incurred during the year ended December 31, 2006	1,176
Liabilities settled during the year ended December 31, 2006	(1,085)
Accretion expense	3,619
Balance of ARO as of December 31, 2006	53,980
Liabilities incurred during the year ended December 31, 2007	3,505
Liabilities settled during the year ended December 31, 2007	(862)
Accretion expense	3,948
Balance of ARO as of December 31, 2007	$ 60,571

The Company also applies FIN 47, Accounting for Conditional Asset Retirement Obligations, which clarifies that if a legal obligation to perform an asset retirement activity exists but performance is conditional upon a future event, the liability is required to be recognized in accordance with SFAS 143 if the obligation can be reasonably measured. Alagasco recorded a conditional asset retirement obligation of $14.4 million and $12.8 million to purge and cap its gas pipelines upon abandonment as a regulatory liability under SFAS No. 71 as of December 31, 2007 and 2006, respectively. The costs associated with asset retirement obligations under FIN 47 are currently either being recovered in rates or are probable of recovery in future rates.

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Alagasco accrues removal costs on certain gas distribution assets over the useful lives of its property, plant and equipment through depreciation expense in accordance with rates approved by the APSC. In accordance with SFAS No. 71, the accumulated asset removal costs of $121.6 million and $114.5 million for December 31, 2007 and 2006, respectively, are included as regulatory liabilities in deferred credits and other liabilities on the consolidated balance sheets.

11. SUPPLEMENTAL CASH FLOW INFORMATION

Supplemental information concerning Energen s cash flow activities was as follows:

Years ended December 31, (in thousands)	**2007**	2006	2005
Interest paid, net of amount capitalized	**$ 44,368**	$ 48,879	$ 43,849
Income taxes paid	**$ 154,187**	$ 60,308	$ 32,879
Noncash investing activities:			
Capitalized depreciation	**$ 97**	$ 99	$ 96
Allowance for funds used during construction	**$ 611**	$ 951	$ 792
Noncash financing activities:			
Issuance of common stock for employee benefit plans	**$ 7,940**	$ 2,410	$ 8,420
Treasury stock acquired in connection with tax withholdings	**$ 6,760**	$ 1,309	$ -

Under SFAS No. 143, the Company recorded a non-cash adjustment for accretion expense of $3.9 million, $3.6 million and $2.6 million during 2007, 2006 and 2005, respectively. In December 2006, the Company adopted SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132 (R). In adopting the standard, the Company recognized noncash adjustments to its financial statements as disclosed in Note 5, Employee Benefit Plans.

Supplemental information concerning Alagasco s cash flow activities was as follows:

Years ended December 31, (in thousands)	**2007**	2006	2005
Interest paid, net of amount capitalized	**$ 12,848**	$ 14,683	$ 12,664
Income taxes paid	**$ 24,579**	$ 21,027	$ 22,456
Noncash investing activities:			
Capitalized depreciation	**$ 97**	$ 99	$ 96
Allowance for funds used during construction	**$ 611**	$ 951	$ 792

12. SUMMARIZED QUARTERLY FINANCIAL DATA *(Unaudited)*

The Company s business is seasonal in character. The following data summarizes quarterly operating results.

	Year Ended December 31, 2007			
(in thousands, except per share amounts)	**First**	**Second**	**Third**	**Fourth**
Operating revenues	**$ 492,661**	**$ 314,922**	**$ 276,022**	**$ 351,455**
Operating income	**$ 173,198**	**$ 115,905**	**$ 98,632**	**$ 134,297**
Income from continuing operations	**$ 103,881**	**$ 67,903**	**$ 58,014**	**$ 79,414**
Net income	**$ 103,882**	**$ 67,903**	**$ 58,034**	**$ 79,414**
Diluted earnings per average common share				
Continuing operations	**$ 1.44**	**$ 0.94**	**$ 0.80**	**$ 1.10**
Net income	**$ 1.44**	**$ 0.94**	**$ 0.80**	**$ 1.10**
Basic earnings per average common share				
Continuing operations	**$ 1.45**	**$ 0.95**	**$ 0.81**	**$ 1.11**
Net income	**$ 1.45**	**$ 0.95**	**$ 0.81**	**$ 1.11**

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	Year Ended December 31, 2006			
(in thousands, except per share amounts)	First	Second	Third	Fourth*
Operating revenues	$ 488,142	$ 282,374	$ 242,711	$ 380,759
Operating income	$ 151,735	$ 89,298	$ 75,669	$ 160,598
Income from continuing operations	$ 87,501	$ 49,602	$ 41,297	$ 95,123
Net income	$ 87,494	$ 49,601	$ 41,352	$ 95,123
Diluted earnings per average common share				
Continuing operations	$ 1.18	$ 0.67	$ 0.56	$ 1.31
Net income	$ 1.18	$ 0.67	$ 0.56	$ 1.31
Basic earnings per average common share				
Continuing operations	$ 1.19	$ 0.68	$ 0.57	$ 1.33
Net income	$ 1.19	$ 0.68	$ 0.57	$ 1.33

* *Includes an after-tax gain of $34.5 million on the sale of a 50 percent interest in Energen Resources acreage position in Alabama shale to Chesapeake Energy Corporation.*

Alagasco s business is seasonal in character and influenced by weather conditions. The following data summarizes Alagasco s quarterly operating results.

Year Ended December 31, 2007

(in thousands)	**First**	**Second**	**Third**	**Fourth**
Operating revenues	**$ 298,628**	**$ 111,566**	**$ 67,599**	**$ 131,675**
Operating income (loss)	**$ 68,437**	**$ 4,970**	**$ (13,673)**	**$ 13,008**
Net income (loss)	**$ 40,329**	**$ 1,378**	**$ (10,541)**	**$ 5,652**

	Year Ended December 31, 2006			
(in thousands)	First	Second	Third	Fourth
Operating revenues	$ 318,623	$ 113,196	$ 71,195	$ 160,430
Operating income (loss)	$ 63,727	$ 2,711	$ (8,921)	$ 16,757
Net income (loss)	$ 37,369	$ (531)	$ (7,673)	$ 8,133

13. ACQUISITION AND DISPOSITIONS OF OIL AND GAS PROPERTIES

During the year ended December 31, 2007, Energen Resources capitalized approximately $32 million of unproved leaseholds costs, more than $28 million of which was related to the Company s acreage position in Alabama shale. Energen used its available cash and existing lines of credit to finance these unproved leasehold costs.

In May 2007, Energen Resources purchased oil properties in the Permian Basin for $18 million. To finance the acquisition, Energen used its available cash and existing lines of credit.

In December 2006, Energen Resources completed a purchase which expanded its operations in the San Juan Basin from Dominion Resources, Inc. effective December 1, 2006 for approximately $30 million. Energen used its available cash and existing lines of credit to finance the acquisition.

In October 2006, Energen Resources sold a 50 percent interest in its lease position in various shale plays in Alabama to Chesapeake for cash and a carried drilling interest. In addition, the two companies have signed an agreement to form an area of mutual interest (AMI) to focus on the further exploration and development of these shale plays throughout Alabama and a part of Georgia. Energen Resources received $75 million in cash from Chesapeake for a 50 percent interest in Energen Resources existing shale lease position of approximately 200,000 net acres in Alabama. Chesapeake also will pay for Energen Resources first $15 million of future drilling costs. During 2007, no significant drilling costs were incurred. Energen Resources had a gain of approximately $34.5 million after-tax in the fourth quarter of 2006 resulting from this sale of its lease position.

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14. REGULATORY ASSETS AND LIABILITIES

The following table details regulatory assets and liabilities on the consolidated balance sheets:

Energen Corporation				
(in thousands)	**December 31, 2007**		December 31, 2006	
	Current	**Noncurrent**	Current	Noncurrent
Regulatory assets:				
Pension asset	**$ -**	**$ 21,160**	$ -	$ 28,476
Accretion and depreciation for asset retirement obligation	**-**	**11,024**	-	9,803
Gas supply adjustment	**9,711**	**-**	23,595	-
Risk management activities	**376**	**-**	11,543	-
Other	**145**	**54**	341	106
Total regulatory assets	**$ 10,232**	**$ 32,238**	$ 35,479	$ 38,385
Regulatory liabilities:				

Enhanced stability reserve	**$ 3,951**	**$ -**	$ 3,951	$ -
RSE adjustment	**3,445**	**-**	1,460	-
Unbilled service margin	**24,725**	**-**	27,233	-
Asset removal costs, net	**-**	**121,573**	-	114,520
Asset retirement obligation	**-**	**14,367**	-	12,833
Pension liability and postretirement benefits, net	**-**	**4,188**	-	7,220
Other	**33**	**995**	1,227	893
Total regulatory liabilities	**$ 32,154**	**$ 141,123**	$ 33,871	$ 135,466

As described in Note 2, Regulatory Matters, Alagasco s rates are established under the RSE rate-setting process and are based on average equity for the period. Alagasco s rates are not adjusted to exclude a return on its investment in regulatory assets during the recovery period.

15. STOCK DIVIDEND

On April 27, 2005, Energen s shareholders approved a 2-for-1 split of the Company s common stock. The split was effected in the form of a 100 percent stock dividend and was payable on June 1, 2005, to shareholders of record on May 13, 2005. All share and per share amounts of capital stock outstanding have been adjusted to reflect the stock split. Effective April 29, 2005, the Restated Certificate of Incorporation of Energen Corporation was amended to increase the Company s authorized common stock, par value $0.01 per share, from 75,000,000 shares to 150,000,000 shares.

16. TRANSACTIONS WITH RELATED PARTIES

Alagasco purchased natural gas of $2,731,000 from affiliates for the year ended December 31, 2005. These amounts were included in gas purchased for resale. All transactions were at market based pricing. Alagasco did not purchase natural gas from affiliated companies in 2007 or 2006.

The Company allocates certain corporate costs to Energen Resources and Alagasco based on the nature of the expense to be allocated using various factors including, but not limited to, total assets, earnings, or number of employees. The Company s cash management program matches short-term cash surpluses with the needs of its affiliates, to minimize borrowing from outside sources. Alagasco had net payables to affiliates of $4,934,000 and $18,130,000 at December 31, 2007 and 2006, respectively. Interest income and expense between affiliates is calculated monthly based on the market weighted average interest rate. The weighted average interest rate during 2007 and 2006 was 5.39 percent and 5.43 percent, respectively.

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17. RECENT PRONOUNCEMENTS OF THE FINANCIAL ACCOUNTING STANDARDS BOARD (FASB)

The Company adopted the provisions of FIN 48 as of January 1, 2007. This Interpretation prescribed a recognition threshold and measurement attribute for the financial statement recognition, measurement and disclosure of a tax position taken or expected to be taken in a tax return. As a result of the implementation of FIN 48, the Company recognized an approximate $1.2 million increase in the liability for unrecognized tax benefits which was accounted for as a decrease to the January 1, 2007 balance of retained earnings. As of the date of adoption and after the impact of recognizing the increase in liability noted above, the Company s unrecognized tax benefits totaled $8.2 million. The amount of unrecognized tax benefits at January 1, 2007 that would favorably impact the Company s effective tax rate, if recognized, was $3.4 million. The Company recognized potential accrued interest and penalties related to unrecognized tax benefits in income tax expense. As of January 1, 2007, the Company recognized approximately $484,000 in potential interest (net of tax benefit) and penalties associated with uncertain tax positions.

During September 2006, the FASB issued SFAS No. 157, Fair Value Measurements, which clarifies that fair value should be based on the assumptions market participants would use when pricing an asset or a liability and establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. Under SFAS No. 157, fair value measurements would be separately disclosed by level within the fair value hierarchy effective for fiscal years beginning after November 15, 2007. The Company is currently evaluating the impact of this Statement. In February 2008, the FASB announced it will issue Final FASB Staff Positions (FSP s) that will partially defer the effective date of

SFAS No. 157 for one year for certain nonfinancial assets and nonfinancial liabilities and remove certain leasing transactions from the scope of SFAS No. 157. The Company will evaluate the impact of the FSP s upon issuance.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities, which permits entities to measure financial instruments and certain other items at fair value to mitigate volatility in reported earnings. This Statement is effective for fiscal years beginning after November 15, 2007. The effect of this Standard on the Company is currently being evaluated.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), Business Combinations, which will improve the relevance, representational faithfulness, and comparability of the information that a reporting entity provides in its financial reports about a business combination and its effects. This Statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first fiscal year beginning on or after December 15, 2008. The Company is currently evaluating the impact of this Statement.

The FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51, in December 2007. SFAS No. 160 establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, changes in a parent s ownership interest, and the valuation of retained noncontrolling equity investments when a subsidiary is deconsolidated. SFAS No. 160 also establishes disclosure requirements that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. This Statement is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. The effect of this Standard on the Company is currently being evaluated.

18. OIL AND GAS OPERATIONS *(Unaudited)*

The following schedules detail historical financial data of the Company s oil and gas operations.

Capitalized Costs

(in thousands)	**December 31, 2007**	December 31, 2006
Proved	**$ 2,477,587**	$ 2,141,874
Unproved	**52,462**	21,191
Total capitalized costs	**2,530,049**	2,163,065
Accumulated depreciation, depletion, and amortization	**664,290**	559,059
Capitalized costs, net	**$ 1,865,759**	$ 1,604,006

Costs Incurred: The following table sets forth costs incurred in property acquisition, exploration and development activities and includes both capitalized costs and costs charged to expense during the year:

Years ended December 31, (in thousands)	**2007**	2006	2005
Property acquisition:			
Proved	**$ 22,439**	$ 24,388	$ 170,338
Unproved	**32,187**	22,040	18,065
Exploration	**8,860**	26,767	5,490
Development	**315,852**	187,734	158,025
Total costs incurred	**$ 379,338**	$ 260,929	$ 351,918

Results of Continuing Operations From Producing Activities: The following table sets forth results of the Company s oil and gas continuing operations from producing activities:

Years ended December 31, (in thousands)	**2007**	2006	2005
Gross revenues	**$ 825,645**	$ 675,830	$ 529,415
Production (lifting costs)	**202,078**	184,362	156,512

Exploration expense	**2,894**	4,181	676
Depreciation, depletion and amortization	**111,567**	95,522	87,398
Accretion expense	**3,948**	3,619	2,647
Income tax expense	**177,083**	140,619	102,102
Results of continuing operation from producing activities	**$ 328,075**	$ 247,527	$ 180,080

Oil and Gas Operations: The calculation of proved reserves is made pursuant to rules prescribed by the SEC. Such rules, in part, require that only proved categories of reserves be disclosed and that reserves and associated values be calculated using year-end prices and current costs. Changes to prices and costs could have a significant effect on the disclosed amount of reserves and their associated values. In addition, the estimation of reserves inherently requires the use of geologic and engineering estimates which are subject to revision as reservoirs are produced and developed and as additional information is available. Accordingly, the amount of actual future production may vary significantly from the amount of reserves disclosed. The proved reserves are located onshore in the United States of America.

Estimates of physical quantities of oil and gas proved reserves were determined by Company engineers. Ryder Scott Company, L.P. and T. Scott Hickman and Associates, Inc., independent oil and gas reservoir engineers, have reviewed the estimates of proved reserves of natural gas, oil and natural gas liquids that the Company has attributed to its net interests in oil and gas properties as of December 31, 2007. Ryder Scott Company, L.P. reviewed the reserve estimates for coalbed methane in the Black Warrior and San Juan basins and substantially all of the Permian Basin reserves. T. Scott Hickman and Associates, Inc. reviewed the reserves for the North Louisiana and East Texas regions and the conventional reserves in the San Juan Basin. The independent reservoir engineers have issued reports covering approximately 98 percent of the Company s ending proved reserves indicating that in their judgment the estimates are reasonable in the aggregate.

Year ended December 31, 2007	**Gas MMcf**	**Oil MBbl**	**NGL MBbl**	**Total Bcfe**
Proved reserves at beginning of period	**1,096,429**	**74,893**	**29,504**	**1,722.8**
Revisions of previous estimates	**2,977**	**(4,573)**	**1,999**	**(12.5)**
Purchases	**483**	**2,202**	**145**	**14.6**
Extensions and discoveries	**80,328**	**5,982**	**1,855**	**127.4**
Production	**(64,299)**	**(3,879)**	**(1,839)**	**(98.6)**
Proved reserves at end of period	**1,115,918**	**74,625**	**31,664**	**1,753.7**
Proved developed reserves at end of period	**903,510**	**61,209**	**28,348**	**1,440.9**

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Year ended December 31, 2006	Gas MMcf	Oil MBbl	NGL MBbl	Total Bcfe
Proved reserves at beginning of period	1,080,161	74,962	31,934	1,721.5
Revisions of previous estimates	(40,458)	(3,518)	(1,449)	(70.2)
Purchases	19,561	81	24	20.2
Extensions and discoveries	99,988	7,013	812	146.9
Production	(62,823)	(3,645)	(1,817)	(95.6)
Proved reserves at end of period	1,096,429	74,893	29,504	1,722.8
Proved developed reserves at end of period	866,874	55,210	26,932	1,359.7

Year ended December 31, 2005	Gas MMcf	Oil MBbl	NGL MBbl	Total Bcfe
Proved reserves at beginning of period	1,019,436	54,500	34,613	1,554.1
Revisions of previous estimates	43,221	186	(1,484)	35.4
Purchases	3,974	21,614	58	134.0
Extensions and discoveries	75,742	1,979	429	90.2
Production	(61,117)	(3,316)	(1,681)	(91.1)
Sales	(1,095)	(1)	(1)	(1.1)
Proved reserves at end of period	1,080,161	74,962	31,934	1,721.5
Proved developed reserves at end of period	891,978	54,901	27,681	1,387.5

Energen Resources had downward reserve revisions during 2007 which totaled 12.5 Bcfe. The Black Warrior Basin had downward reserve revisions totaling 3 Bcfe of which approximately 6.1 Bcfe related to changes in year-end pricing which accelerated reversions in ownership partially offset by an estimated 3.1 Bcfe of upward revisions associated with improved performance. In the San Juan Basin, upward reserve revisions of 9.2 Bcfe were largely due to 25 Bcfe of estimated price-revisions partially offset by a 16 Bcfe decrease for the removal of proved undeveloped locations due to new reservoir interpretations. Downward reserve revisions of 21.4 Bcfe in the Permian Basin were largely a result delayed waterflood responses estimated at 34.1 Bcfe partially offset by upward price revisions of approximately 12.7 Bcfe.

Energen Resources purchased 14.6 Bcfe of reserves during 2007 primarily related to the acquisition of oil properties in the Permian Basin.

During 2007, Energen Resources had extensions and discoveries of 127.4 Bcfe of which 65 percent were proved undeveloped reserves and 35 percent were proved developed reserves. Extension drilling resulted in discoveries of 109.7 Bcfe with exploratory drilling providing 17.7 Bcfe of discoveries. The Black Warrior Basin added 20.5 Bcfe of reserves primarily through the drilling or identification of 55 well locations. The San Juan Basin added 47.2 Bcfe of reserves through the drilling or identification of 92 well locations; additionally, 18 sidetrack wells added 12.9 Bcfe of reserves. The Permian Basin added 30.1 Bcfe of reserves through the drilling or identification of 128 well locations.

For the year ended December 31, 2006, Energen Resources had downward reserve revisions which totaled 70.2 Bcfe and were primarily the result of reduced year-end pricing. Purchases for 2006 added 20.2 Bcfe of reserves and related primarily to an acquisition of gas properties in the San Juan Basin. Extension and discoveries during 2006 totaled 146.9 Bcfe of reserves, the majority of which related to extension drilling.

During 2005, Energen Resources had upward reserve revisions totaling 35.4 Bcfe largely due to changes in year-end pricing. Other reserve revisions related to changes in the reservoirs performance. Purchases for 2005 added 134 Bcfe of reserves and related primarily to the acquisition of oil properties in the Permian Basin. Energen Resources had extensions and discoveries during 2005 totaling 90.2 Bcfe of reserves, the majority of which related to extension drilling. During 2005, Energen Resources sold approximately 1.1 Bcfe of proved reserves, recording a net pre-tax gain of $1.7 million on certain properties in the Permian and Black Warrior basins.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves: The standardized measure of discounted future net cash flows is not intended, nor should it be interpreted, to present the fair market value of the Company s crude oil and natural gas reserves. An estimate of fair market value would

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take into consideration factors such as, but not limited to, the recovery of reserves not presently classified as proved reserves, anticipated future changes in prices and costs, and a discount factor more representative of the time value of money and the risks inherent in reserve estimates. At December 31, 2007, 2006 and 2005, the Company had a deferred hedging loss of $104.9 million, a deferred hedging gain of $81.5 million, and a deferred hedging loss of $148.6 million, respectively, all of which are excluded from the calculation of standardized measure of future net cash flows.

Years ended December 31, (in thousands)	**2007**	2006	2005
Future gross revenues	**$ 15,789,245**	$ 11,012,667	$ 14,252,735
Future production costs	**4,682,021**	3,909,649	4,168,061
Future development costs	**471,655**	556,131	357,408
Future income tax expense	**3,501,519**	2,062,210	3,268,157
Future net cash flows	**7,134,050**	4,484,677	6,459,109
Discount at 10% per annum	**3,869,337**	2,338,576	3,547,454
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	**$ 3,264,713**	$ 2,146,101	$ 2,911,655
Discounted future net cash flows before income taxes	**$ 4,470,808**	$ 2,827,411	$ 4,045,529

Reserves and associated values were calculated using year-end prices and current costs. The following are the principal sources of changes in the standardized measure of discounted future net cash flows:

	Year Ended December 31,	Year Ended December 31,	Year Ended December 31,
Years ended December 31, (in thousands)	**2007**	2006	2005
Balance at beginning of year	**$ 2,146,101**	$ 2,911,655	$ 1,891,418
Revisions to reserves proved in prior years:			
Net changes in prices, production costs and future development costs	**1,556,198**	(1,489,312)	1,288,366

Net changes due to revisions in quantity estimates	**(32,074)**	(123,057)	90,952
Development costs incurred, previously estimated	**215,155**	86,554	101,740
Accretion of discount	**214,610**	291,166	189,142
Other	**(135,935)**	159,945	(69,803)
Total revisions	**1,817,954**	(1,074,704)	1,600,397
New field discoveries and extensions, net of future production and development costs	**327,564**	253,277	235,832
Sales of oil and gas produced, net of production costs	**(598,720)**	(549,559)	(595,439)
Purchases	**28,468**	39,481	199,319
Sales	**-**	-	(2,474)
Net change in income taxes	**(456,654)**	565,951	(417,398)
Net change in standardized measure of discounted future net cash flows	**1,118,612**	(765,554)	1,020,237
Balance at end of year	**$ 3,264,713**	$ 2,146,101	$ 2,911,655

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19. INDUSTRY SEGMENT INFORMATION

The Company is principally engaged in two business segments: the acquisition, development, exploration and production of oil and gas in the continental United States (oil and gas operations) and the purchase, distribution and sale of natural gas in central and north Alabama (natural gas distribution). The accounting policies of the segments are the same as those described in Note 1, Summary of Significant Accounting Policies. Certain reclassifications have been made to conform the prior years financial statements to the current year presentation.

(in thousands)	**Year Ended December 31, 2007**	Year Ended December 31, 2006	Year Ended December 31, 2005
Operating revenues from continuing operations			
Oil and gas operations	**$ 825,592**	$ 730,542	$ 530,341
Natural gas distribution	**609,468**	663,444	600,700
Eliminations and other	**-**	-	(2,647)
Total	**$ 1,435,060**	$ 1,393,986	$ 1,128,394
Operating income (loss) from continuing operations			
Oil and gas operations	**$ 451,567**	$ 405,149	$ 243,876
Natural gas distribution	**72,742**	74,274	72,922
Subtotal	**524,309**	479,423	316,798
Eliminations and corporate expenses	**(2,277)**	(2,123)	(1,074)
Total	**$ 522,032**	$ 477,300	$ 315,724
Depreciation, depletion and amortization expense from continuing operations			
Oil and gas operations	**$ 114,241**	$ 97,842	$ 89,340
Natural gas distribution	**47,136**	44,244	42,351
Total	**$ 161,377**	$ 142,086	$ 131,691
Interest expense			
Oil and gas operations	**$ 32,673**	$ 33,542	$ 32,778
Natural gas distribution	**15,696**	16,454	15,060
Subtotal	**48,369**	49,996	47,838
Eliminations and other	**(1,269)**	(1,344)	(1,038)
Total	**$ 47,100**	$ 48,652	$ 46,800
Income tax expense (benefit) from continuing operations			
Oil and gas operations	**$ 147,418**	$ 134,938	$ 76,362

Natural gas distribution	**21,636**	22,002	22,360
Subtotal	**169,054**	156,940	98,722
Other	**(1,625)**	(1,910)	(1,231)
Total	**$ 167,429**	$ 155,030	$ 97,491
Capital expenditures			
Oil and gas operations	**$ 379,479**	$ 259,678	$ 353,712
Natural gas distribution	**58,862**	76,157	73,276
Total	**$ 438,341**	$ 335,835	$ 426,988
Identifiable assets			
Oil and gas operations	**$ 2,065,229**	$ 1,822,216	$ 1,637,244
Natural gas distribution	**980,813**	1,006,096	946,819
Subtotal	**3,046,042**	2,828,312	2,584,063
Eliminations and other	**33,611**	8,575	34,163
Total	**$ 3,079,653**	$ 2,836,887	$ 2,618,226
Property, plant and equipment, net			
Oil and gas operations	**$ 1,877,747**	$ 1,612,764	$ 1,470,063
Natural gas distribution	**660,496**	639,650	597,948
Total	**$ 2,538,243**	$ 2,252,414	$ 2,068,011

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SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS

Energen Corporation

Years ended December 31, (in thousands)	**2007**	2006	2005
ALLOWANCE FOR DOUBTFUL ACCOUNTS			
Balance at beginning of year	**$ 13,961**	$ 11,573	$ 10,472
Additions:			
Charged to income	**5,610**	6,972	6,076
Recoveries and adjustments	**(202)**	(232)	(431)
Net additions	**5,408**	6,740	5,645
Less uncollectible accounts written off	**(7,125)**	(4,352)	(4,544)
Balance at end of year	**$ 12,244**	$ 13,961	$ 11,573

Alabama Gas Corporation

Years ended December 31, (in thousands)	**2007**	2006	2005
ALLOWANCE FOR DOUBTFUL ACCOUNTS			
Balance at beginning of year	**$ 13,200**	$ 10,800	$ 9,600
Additions:			
Charged to income	**5,610**	6,972	6,076
Recoveries and adjustments	**(197)**	(227)	(342)
Net additions	**5,413**	6,745	5,734
Less uncollectible accounts written off	**(7,113)**	(4,345)	(4,534)
Balance at end of year	**$ 11,500**	$ 13,200	$ 10,800

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ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE
None

ITEM 9A. CONTROLS AND PROCEDURES
Energen Corporation

a. Disclosure Controls and Procedures

Our chief executive officer and chief financial officer of Energen Corporation have evaluated the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation they have concluded that our disclosure controls and procedures are effective as of December 31, 2007 at a reasonable assurance level.

b. Management s Report On Internal Control Over Financial Reporting

Management of Energen Corporation is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. Energen Corporation 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 accounting principles generally accepted in the United States of America. Internal control over financial reporting includes those written policies and procedures that:

i pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of Energen Corporation;

ii provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures of Energen Corporation are being made only in accordance with authorization of management and directors of Energen Corporation; and

iii provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of assets that could have a material effect on the consolidated 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.

Management assessed the effectiveness of Energen Corporation s internal control over financial reporting as of December 31, 2007. Management based this assessment on criteria for effective internal control over financial reporting described in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management s assessment included an evaluation of the design of Energen Corporation s internal control over financial reporting and testing of the operational effectiveness of its internal control over financial reporting. Management reviewed the results of its assessment with the Audit Committee of our Board of Directors.

Based on this assessment, management determined that, as of December 31, 2007, Energen Corporation maintained effective internal control over financial reporting. The effectiveness of Energen Corporation s internal control over financial reporting as of December 31, 2007 has been audited by PricewaterhouseCoopers, LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 25, 2008

c. Changes in Internal Control Over Financial Reporting

Our chief executive officer and chief financial officer of Energen Corporation have concluded that during the most recent fiscal quarter covered by this report there were no changes in our internal control over financial reporting that materially affected or are reasonably likely to materially affect our internal control over financial reporting.

Alabama Gas Corporation

a. Disclosure Controls and Procedures

Our chief executive officer and chief financial officer of Alabama Gas Corporation have evaluated the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation they have concluded that our disclosure controls and procedures are effective as of December 31, 2007 at a reasonable assurance level.

b. Management s Report On Internal Control Over Financial Reporting

Management of Alabama Gas Corporation is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. Alabama Gas Corporation 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 accounting principles generally accepted in the United States of America. Internal control over financial reporting includes those written policies and procedures that:

i pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of Alabama Gas Corporation;

ii provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures of Alabama Gas Corporation are being made only in accordance with authorization of management and directors of Alabama Gas Corporation; and

iii provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of assets that could have a material effect on the consolidated 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.

Management assessed the effectiveness of Alabama Gas Corporation s internal control over financial reporting as of December 31, 2007. Management based this assessment on criteria for effective internal control over financial reporting described in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management s assessment included an evaluation of the design of Alabama Gas Corporation s internal control over financial reporting and testing of the operational effectiveness of its internal control over financial reporting. Management reviewed the results of its assessment with the Audit Committee of our Board of Directors.

Based on this assessment, management determined that, as of December 31, 2007, Alabama Gas Corporation maintained effective internal control over financial reporting.

February 25, 2008

c. Changes in Internal Control Over Financial Reporting

Our chief executive officer and chief financial officer of Alabama Gas Corporation have concluded that during the most recent fiscal quarter covered by this report there were no changes in our internal control over financial reporting that materially affected or are reasonably likely to materially affect our internal control over financial reporting.

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information regarding the executive officers of Energen is included in Part I. The other information required by Item 10 is incorporated herein by reference from Energen s definitive proxy statement for the Annual Meeting of Shareholders to be held April 23, 2008. The definitive proxy statement will be filed on or about March 24, 2008.

ITEM 11. EXECUTIVE COMPENSATION

The information regarding executive compensation is incorporated herein by reference from Energen s definitive proxy statement for the Annual Meeting of Shareholders to be held April 23, 2008.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

a. Security Ownership of Certain Beneficial Owners

The information regarding the security ownership of the beneficial owners of more than five percent of Energen s common stock is incorporated herein by reference from Energen s definitive proxy statement for the Annual Meeting of Shareholders to be held April 23, 2008.

b. Security Ownership of Management

The information regarding the security ownership of management is incorporated herein by reference from Energen s definitive proxy statement for the Annual Meeting of Shareholders to be held April 23, 2008.

c. Securities Authorized for Issuance Under Equity Compensation Plans

The information regarding securities authorized for issuance under equity compensation plans is included in Part 2 under Item 5.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information regarding certain relationships and related transactions, and director independence is incorporated herein by reference from Energen s definitive proxy statement for the Annual Meeting of Shareholders to be held April 23, 2008.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information regarding Principal Accountant Fees and Services is incorporated herein by reference from Energen s definitive proxy statement for the Annual Meeting of Shareholders to be held April 23, 2008.

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

a. Documents Filed as Part of This Report

(1) Financial Statements

The consolidated financial statements of Energen and the financial statements of Alagasco are included in Item 8 of this Form 10-K

(2) Financial Statement Schedules

The financial statement schedules are included in Item 8 of this Form 10-K

(3) Exhibits

The exhibits listed on the accompanying Index to Exhibits are filed as part of this Form 10-K

Energen Corporation

Alabama Gas Corporation

INDEX TO EXHIBITS

Item 14(a)(3)

Exhibit Number	**Description**
*3(a)	Restated Certificate of Incorporation of Energen Corporation (composite, as amended April 29, 2005) which was filed as Exhibit 3(a) to Energen s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2005
*3(b)	Articles of Amendment to Restated Certificate of Incorporation of Energen, designating Series 1998 Junior Participating Preferred Stock (July 27, 1998) which was filed as Exhibit 4(b) to Energen s Post Effective Amendment No. 1 to Registration Statement on Form S-3 (Registration No. 333-00395)
*3(c)	Bylaws of Energen Corporation (as amended through October 30, 2002) which was filed as Exhibit 4(c) to Energen s Registration Statement on Form S-8 (Registration No. 33-46641)
*3(d)	Articles of Amendment and Restatement of the Articles of Incorporation of Alabama Gas Corporation, dated September 27, 1995, which was filed as Exhibit 3(i) to the Registrant s Annual Report on Form 10-K for the year ended September 30, 1995
*3(e)	Bylaws of Alabama Gas Corporation (as amended through October 24, 2007) which was filed as Exhibit 3 to Energen s Quarterly Report on Form 10-Q for the period ended October 31, 2007
*4(a)	Rights Agreement, dated as of July 27, 1998, between Energen Corporation and First Chicago Trust Company of New York, Rights Agent, which was filed as Exhibit 1 to Energen s Registration Statement on Form 8-A, dated July 10, 1998
*4(b)	Form of Indenture between Energen Corporation and The Bank of New York, as Trustee, which was dated as of September 1, 1996 (the Energen 1996 Indenture), and which was filed as Exhibit 4(i) to the Registrant s Registration Statement on Form S-3 (Registration No. 333-11239)
*4(b)(i)	Officers Certificate, dated September 13, 1996, pursuant to Section 301 of the Energen 1996 Indenture setting forth the terms of the Series A Notes which was filed as Exhibit 4(d)(i) to Energen s Annual Report on Form 10-K for the year ended September 30, 2001
*4(b)(ii)	Officers Certificate, dated July 8, 1997, pursuant to Section 301 of the Energen 1996 Indenture amending the terms of the Series A Notes which was filed as Exhibit 4(d)(ii) to Energen s Annual Report on Form 10-K for the year ended September 30, 2001

*4(b)(iii)	Amended and Restated Officers Certificate, dated February 27, 1998, setting forth the terms of the Series B Notes which was filed as Exhibit 4(d)(iii) to Energen s Annual Report on Form 10-K for the year ended September 30, 2001
*4(b)(iv)	Officers Certificate, dated October 3, 2003, pursuant to Section 301 of the Energen 1996 Indenture setting forth the terms of the 5 percent Notes due October 1, 2013, which was filed as Exhibit 4 to Energen s Current Report on Form 8-K, dated October 3, 2003
*4(c)	Indenture dated as of November 1, 1993, between Alabama Gas Corporation and NationsBank of Georgia, National Association, Trustee, (Alagasco 1993 Indenture), which was filed as Exhibit 4(k) to Alabama Gas Registration Statement on Form S-3 (Registration No. 33-70466)

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*4(c)(i)	Officers Certificate, dated January 14, 2005, pursuant to Section 301 of the Alagasco 1993 Indenture setting forth the terms of the 5.70 percent Notes due January 15, 2035, which was filed as Exhibit 4.3 to Alabama Gas Current Report on Form 8-K filed January 14, 2005
*4(c)(ii)	Officers Certificate, dated January 14, 2005, pursuant to Section 301 of the Alagasco 1993 Indenture setting forth the terms of the 5.20 percent Notes due January 15, 2020, which was filed as Exhibit 4.4 to Alabama Gas Current Report on Form 8-K filed January 14, 2005
*4(c)(iii)	Officers Certificate, dated November 17, 2005, pursuant to Section 301 of the Alagasco 1993 Indenture setting forth the terms of the 5.368 percent Notes due December 1, 2015, which was filed as Exhibit 4.2 to Alabama Gas Current Report on Form 8-K filed November 17, 2005
*4(c)(iv)	Officers Certificate, dated January 16, 2007, pursuant to Section 301 of the Alagasco 1993 Indenture setting forth the terms of the 5.90 percent Notes due January 15, 2037, which was filed as Exhibit 4.2 to Alabama Gas Current Report on Form 8-K filed January 16, 2007
*10(a)	Service Agreement Under Rate Schedule CSS (No. SSNG1), between Southern Natural Gas Company and Alabama Gas Corporation, dated as of September 1, 2005, which was filed as Exhibit 10(a) to Energen s Annual Report on Form 10-K for the year ended December 31, 2005
*10(b)	Firm Transportation Service Agreement Under Rate Schedule FT and/or FT-NN (No. FSNG1), between Southern Natural Gas Company and Alabama Gas Corporation dated as of September 1, 2005, which was filed as Exhibit 10(b) to Energen s Annual Report on Form 10-K for the year ended December 31, 2005
*10(c)	Form of Service Agreement Under Rate Schedule IT (No. 790420), between Southern Natural Gas Company and Alabama Gas Corporation, which was filed as Exhibit 10(b) to Energen s Annual Report on Form 10-K for the year ended September 30, 1993
*10(d)	Service Agreement between Transcontinental Gas Pipeline Corporation and Transco Energy Marketing Company as Agent for Alabama Gas Corporation, dated August 1, 1991 which was filed as Exhibit 3(e) to Energen s Annual Report on Form 10-K for the year ended December 31, 2003
*10(e)	Amendment to Service Agreement between Transcontinental Gas Pipeline Corporation and Alabama Gas Corporation, dated December 2, 2005, which was filed as Exhibit 10(e) to Energen s Annual Report on Form 10-K for the year ended December 31, 2005
*10(f)	Occluded Gas Lease, dated January 1, 1986 and First through Seventh Amendments, which was filed as Exhibit 10(f) to Energen s Annual Report on Form 10-K for the year ended December 31, 2005
*10(g)	Form of Executive Retirement Supplement Agreement between Energen Corporation and it s executive officers (as revised October 2000) which was filed as Exhibit 10(c) to Energen s Annual Report on Form 10-K for the year ended September 30, 2000
*10(h)	Amendment to Executive Retirement Supplement Agreement with Mr. Warren, dated December 13, 2006, which was filed as Exhibit 99.2 to Energen s Current Report on Form 8-K, filed December 14, 2006
*10(i)	Amendment to Executive Retirement Supplement Agreement with Mr. Ketcham, dated December 13, 2006, which was filed as Exhibit 99.3 to Energen s Current Report on Form 8-K, filed December 14, 2006

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*10(j)	Form of Severance Compensation Agreement between Energen Corporation and it s executive officers which was filed as Exhibit 99.1 to Energen s Current Report on Form 8-K, dated January 29, 2007
*10(k)	

	Energen Corporation 1997 Stock Incentive Plan (as amended effective January 1, 2007) which was filed as Exhibit 10 to Energen s Quarterly Report on Form 10-Q for the period ended March 31, 2007
*10(l)	Form of Stock Option Agreement under the Energen Corporation 1997 Stock Incentive Plan which was filed as Exhibit 10(a) to Energen s Quarterly Report on Form 10-Q for the quarter ended September 30, 2004
*10(m)	Form of Restricted Stock Agreement under the Energen Corporation 1997 Stock Incentive Plan which was filed as Exhibit 10(b) to Energen s Quarterly Report on Form 10-Q for the quarter ended September 30, 2004
*10(n)	Form of Performance Share Award under the Energen Corporation 1997 Stock Incentive Plan which was filed as Exhibit 10(c) to Energen s Quarterly Report on Form 10-Q for the quarter ended September 30, 2004
10(o)	Energen Corporation 1997 Deferred Compensation Plan (amended and restated effective January 1, 2008)
10(p)	Energen Corporation 1992 Directors Stock Plan (as amended December 12, 2007)
*10(q)	Energen Corporation Annual Incentive Compensation Plan, as amended effective October 25, 2006 which was filed as Exhibit 99.1 to Energen s Current Report on Form 8-K, filed October 30, 2006
*10(r)	Energen Corporation Officer Split Dollar Life Insurance Plan, effective October 1, 1999 which was filed as Exhibit 10(l) to Energen s Annual Report on Form 10-K for the year ended September 30, 2000 (File No. 1-7810)
*10(s)	Form of Split Dollar Life Insurance Plan Agreement under Energen Corporation Officer Split Dollar Life Insurance Plan which was filed as Exhibit 10(m) to Energen s Annual Report on Form 10-K for the year ended September 30, 2000 (File No. 1-7810)
*10(t)	Officer Split Dollar Tax Matters Agreement which was filed as Exhibit 10(n) to Energen s Annual Report on Form 10-K for the year ended September 30, 2000 (File No. 1-7810)
*10(u)	Energen Board of Directors resolution adopted as of May 14, 2004, terminating the Energen Corporation Officer Split Dollar Life Insurance Plan which was filed as Exhibit 10(u) to Energen s Annual Report on Form 10K for the year ended December 31, 2005
21	Subsidiaries of Energen Corporation
23(a)	Consent of Registered Public Accounting Firm (PricewaterhouseCoopers LLP)
23(b)	Consent of Registered Public Accounting Firm (PricewaterhouseCoopers LLP)
23(c)	Consent of Independent Oil and Gas Reservoir Engineers (Ryder Scott Company, L.P.)
23(d)	Consent of Independent Oil and Gas Reservoir Engineers (T. Scott Hickman and Associates, Inc.)
31(a)	Energen Corporation Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a)

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31(b)	Energen Corporation Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a)
31(c)	Alabama Gas Corporation Certification of Chief Executive Officer pursuant to Rule 13a- 14(a) or 15d- 14(a)
31(d)	Alabama Gas Corporation Certification of Chief Financial Officer pursuant to Rule 13a- 14(a) or 15d- 14(a)
32	Certification pursuant to Section 1350

* Incorporated by reference

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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities and Exchange Act of 1934, the Registrants have duly caused this report to be signed on their behalf by the undersigned thereunto duly authorized.

ENERGEN CORPORATION

(Registrant)

ALABAMA GAS CORPORATION

(Registrant)

February 25, 2008	By /s/ James T. McManus II James T. McManus II Chairman, Chief Executive Officer and President of Energen Corporation; Chairman and Chief Executive Officer of Alabama Gas Corporation

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SIGNATURES

Pursuant to the requirements of the Securities and Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrants and in the capacities and on the dates indicated:

February 25, 2008	By /s/ James T. McManus II James T. McManus II Chairman, Chief Executive Officer and President of Energen Corporation; Chairman and Chief Executive Officer of Alabama Gas Corporation
February 25, 2008	By /s/ Charles W. Porter, Jr. Charles W. Porter, Jr. Vice President, Chief Financial Officer and Treasurer of Energen Corporation and Alabama Gas Corporation
February 25, 2008	By /s/ Grace B. Carr Grace B. Carr Vice President and Controller of Energen Corporation
February 25, 2008	By /s/ Paula H. Rushing Paula H. Rushing Vice President-Finance of Alabama Gas Corporation
February 25, 2008	By /s/ Julian W. Banton Julian W. Banton Director
February 25, 2008	By /s/ Kenneth W. Dewey Kenneth W. Dewey Director
February 25, 2008	By /s/ James S. M. French James S. M. French Director
February 25, 2008	By /s/ Judy M. Merritt Judy M. Merritt Director
February 25, 2008	By /s/ Wm. Michael Warren, Jr. Wm. Michael Warren, Jr.

Director

February 25, 2008

By /s/ David W. Wilson
David W. Wilson
Director