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

Form 10-K

ANNUAL REPORT PURSUANT TO
SECTIONS 13 OR 15(d) OF THE SECURITIES EXCHANGE OF 1934

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2005

Commission file number 1-11607

DTE ENERGY COMPANY
(Exact name of registrant as specified in its charter)

Michigan	**38-3217752**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
2000 2nd Avenue, Detroit, Michigan	**48226-1279**
(Address of principal executive offices)	(Zip Code)

313-235-4000
(Registrant's telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common Stock, without par value, with contingent preferred stock purchase rights	New York and Chicago Stock Exchanges
7.8% Trust Preferred Securities *	New York Stock Exchange
7.50% Trust Originated Preferred Securities**	New York Stock Exchange

* Issued by DTE Energy Trust I. DTE Energy fully and unconditionally guarantees the payments of all amounts due on these securities to the extent DTE Energy Trust I has funds available for payment of such distributions.

** Issued by DTE Energy Trust II. DTE Energy fully and unconditionally guarantees the payments of all amounts due on these securities to the extent DTE Energy Trust II has funds available for payment of such distributions.

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

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

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

Indicate by 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 the 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, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☑

On June 30, 2005, the aggregate market value of the Registrant's voting and non-voting common equity held by non-affiliates was approximately $8.1 billion (based on the New York Stock Exchange closing price on such date). There were 177,812,509 shares of common stock outstanding at January 31, 2006.

Certain information in DTE Energy Company's definitive Proxy Statement for its 2006 Annual Meeting of Common Shareholders to be held April 27, 2006, which will be filed with the Securities and Exchange Commission pursuant to Regulation 14A, not later than 120 days after the end of the Registrant's fiscal year covered by this report on Form 10-K, is incorporated herein by reference to Part III (Items 10, 11, 12, 13 and 14) of this Form 10-K.

DTE Energy Company
Annual Report on Form 10-K
Year Ended December 31, 2005

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definitions

Coke and Coke Battery	Raw coal is heated to high temperatures in ovens to separate impurities, leaving a carbon residue called coke. Coke is combined with iron ore to create a high metallic iron that is used to produce steel. A series of coke ovens configured in a module is referred to as a battery.
Company	DTE Energy Company and any subsidiary companies
Customer Choice	Statewide initiatives giving customers in Michigan the option to choose alternative suppliers for electricity and gas.
Detroit Edison	The Detroit Edison Company (a direct wholly owned subsidiary of DTE Energy Company) and subsidiary companies
DTE Energy	DTE Energy Company, directly or indirectly the parent of Detroit Edison, MichCon and numerous non-utility subsidiaries
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GCR	A gas cost recovery mechanism authorized by the MPSC, permitting MichCon to pass the cost of natural gas to its customers.
ITC	International Transmission Company (until February 28, 2003, a wholly owned subsidiary of DTE Energy Company)
MichCon	Michigan Consolidated Gas Company (an indirect wholly owned subsidiary of DTE Energy) and subsidiary companies
MDEQ	Michigan Department of Environmental Quality
MPSC	Michigan Public Service Commission
Non-utility	An entity that is not a public utility. Its conditions of service, prices of goods and services and other operating related matters are not directly regulated by the MPSC or the FERC.
NRC	Nuclear Regulatory Commission
PSCR	A power supply cost recovery mechanism authorized by the MPSC that allows Detroit Edison to recover through rates its fuel, fuel-related and purchased power expenses. The power supply cost recovery mechanism was suspended under Michigan's restructuring legislation (signed into law June 5, 2000), which lowered and froze electric customer rates and was reinstated by the MPSC effective January 1, 2004.
Production tax credits	Tax credits as authorized under Section 29 (redesignated by the Energy Tax Incentives Act of 2005 as Section 45K for tax years after 2005) and Section 45 of the Internal Revenue Code that are designed to stimulate investment in and development of alternate fuel sources. The amount of a production tax credit can vary each year as determined by the Internal Revenue Service.
Proved Reserves	Estimated quantities of natural gas, natural gas liquids and crude oil which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reserves under existing economic and operating conditions.
Securitization	Detroit Edison financed specific stranded costs at lower interest rates through the sale of rate reduction bonds by a wholly-owned special purpose entity, the Detroit Edison Securitization Funding LLC.

SFAS	Statement of Financial Accounting Standards
Stranded Costs	Costs incurred by utilities in order to serve customers in a regulated environment that absent special regulatory approval would not otherwise be recoverable if customers switch to alternative energy suppliers.
Synfuels	The fuel produced through a process involving chemically modifying and binding particles of coal. Synfuels are used for power generation and coke production. Synfuel production generates production tax credits.
Unconventional Gas	Includes those oil and gas deposits that originated and are stored in coal bed, tight sandstone and shale formations.

Units of Measurement

Bcf	Billion cubic feet of gas
Bcfe	Conversion metric of natural gas, the ratio of 6 Mcf of gas to 1 barrel of oil.
kWh	Kilowatthour of electricity
Mcf	Thousand cubic feet of gas
MMcf	Million cubic feet of gas
MW	Megawatt of electricity
MWh	Megawatthour of electricity

Forward-Looking Statements

Certain information presented herein includes forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Forward-looking statements involve certain risks and uncertainties that may cause actual future results to differ materially from those presently contemplated, projected, estimated or budgeted. Many factors may impact forward-looking statements including, but not limited to, the following:

- the higher price of oil and its impact on the value of production tax credits, and the ability to utilize and/or sell interests in facilities producing such credits;
- the uncertainties of successful exploration of gas shale resources and inability to estimate gas reserves with certainty;
- the effects of weather and other natural phenomena on operations and sales to customers, and purchases from suppliers;
- economic climate and population growth or decline in the geographic areas where we do business;
- environmental issues, laws, regulations, and the cost of remediation and compliance;
- nuclear regulations and operations associated with nuclear facilities;
- implementation of electric and gas Customer Choice programs;
- impact of electric and gas utility restructuring in Michigan, including legislative amendments;
- employee relations and the impact of collective bargaining agreements;
- unplanned outages;
- access to capital markets and capital market conditions and the results of other financing efforts which can be affected by credit agency ratings;
- the timing and extent of changes in interest rates;
- the level of borrowings;
- changes in the cost and availability of coal and other raw materials, purchased power and natural gas;
- effects of competition;
- impact of regulation by the FERC, MPSC, NRC and other applicable governmental proceedings and regulations;
- contributions to earnings by non-utility subsidiaries;
- changes in federal, state and local tax laws and their interpretations, including the Internal Revenue Code, regulations, rulings, court proceedings and audits;
- the ability to recover costs through rate increases;
- the availability, cost, coverage and terms of insurance;
- the cost of protecting assets against, or damage due to, terrorism;
- changes in accounting standards and financial reporting regulations;
- changes in federal or state laws and their interpretation with respect to regulation, energy policy and other business issues;
- uncollectible accounts receivable;
- litigation and related appeals; and
- changes in the economic and financial viability of our suppliers, customers and trading counterparties, and the continued ability of such parties to perform their obligations to the Company.

New factors emerge from time to time. We cannot predict what factors may arise or how such factors may cause our results to differ materially from those contained in any forward-looking statement. Any forward-looking statements speak only as of the date on which such statements are made. We undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events.

Items 1., 1A. & 2. Business, Company Risk Factors and Properties

General

In 1995, DTE Energy incorporated in the State of Michigan. Our utility operations consist primarily of Detroit Edison and MichCon. We also have three non-utility segments that are engaged in a variety of energy related businesses such as synfuels, energy services, natural gas exploration and production, energy marketing and trading, coal transportation and gas storage and transportation. In August 2005, the Energy Policy Act of 2005 repealed the Public Utility Holding Company Act of 1935 (PUHCA), effective February 8, 2006. As a result of the repeal of PUHCA, DTE Energy no longer has to claim itself as an exempt holding company. A discussion of the Energy Policy Act of 2005 is in the Management's Discussion and Analysis section of this Form 10-K.

Detroit Edison is a Michigan corporation organized in 1903 and is a public utility subject to regulation by the MPSC and the FERC. Detroit Edison is engaged in the generation, purchase, distribution and sale of electricity to approximately 2.2 million customers in southeastern Michigan.

MichCon is a Michigan corporation organized in 1898 and is a public utility subject to regulation by the MPSC. MichCon is engaged in the purchase, storage, transmission, distribution and sale of natural gas to approximately 1.3 million customers throughout Michigan.

Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to such reports are available free of charge through the Investor Relations page of our website: *www.dteenergy.com*, as soon as reasonably practicable after they are filed with or furnished to the Securities and Exchange Commission (SEC). The information on our website is not, and shall not be deemed to be, a part of this Form 10-K or any other filing we make with the SEC. Our previously filed reports and statements are also available at the SEC's website: *www.sec.gov*.

References in this report to "we," "us," "our" or "Company" are to DTE Energy and its subsidiaries, collectively.

Corporate Structure

Through 2004, we operated our businesses through three strategic business units (Energy Resources, Energy Distribution and Energy Gas). Each business unit had utility and non-utility operations. The balance of our business consisted of Corporate & Other. See Note 16 for financial information by segment for the last three years. Beginning in the second quarter of 2005, we realigned our operations into the following business units to strengthen the Company's focus on customer relationships and growth within our non-utility businesses. Based on this structure, we set strategic goals, allocate resources and evaluate performance.

Electric Utility

- Consists of Detroit Edison, the company's electric utility whose operations include the power generation and electric distribution facilities that service approximately 2.2 million residential, commercial, industrial and wholesale customers throughout southeastern Michigan.

Gas Utility

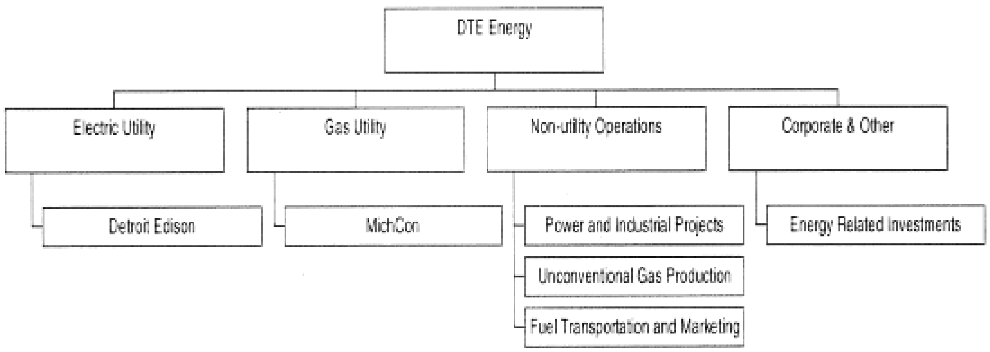
- Consists of the gas distribution services provided by MichCon, a gas utility that purchases, stores and distributes natural gas throughout Michigan to approximately 1.3 million residential, commercial and industrial customers and Citizens Gas Fuel Company (Citizens), a gas utility that distributes natural gas in Adrian, Michigan.

Non-Utility Operations

- *Power and Industrial Projects*, primarily consisting of synfuel projects, on-site energy services, steel-related energy projects, power generation with services, and waste coal recovery operations;

- *Unconventional Gas Production,* primarily consisting of natural gas exploration, development and production; and
- *Fuel Transportation and Marketing*, primarily consisting of energy marketing and trading operations, coal transportation and marketing, and gas pipelines, processing and storage.

Corporate & Other, primarily consisting of corporate support functions and certain energy related investments.



Refer to our Management's Discussion and Analysis for an in-depth analysis of each segment's financial results. A description of each business unit follows.

ELECTRIC UTILITY

Description

Our Electric Utility segment consists of Detroit Edison, an electric utility subject to regulation by the MPSC and FERC. Detroit Edison is engaged in the generation, purchase, distribution and sale of electric energy to approximately 2.2 million customers in a 7,600 square mile area in southeastern Michigan.

Our plants are regulated by numerous federal and state governmental agencies, including the MPSC, the FERC, the NRC, the EPA and the MDEQ. Electricity is generated from our numerous fossil plants, a hydroelectric pumped storage plant and a nuclear plant, and is purchased from electricity generators, suppliers and wholesalers. The electricity we produce and purchase is sold to four major classes of customers: residential, commercial, industrial and wholesale, principally throughout Michigan.

Revenue by Service

(in Millions)	2005	2004	2003
Residential	**$ 1,517**	$ 1,345	$ 1,351
Commercial	**1,331**	1,123	1,308
Industrial	**697**	557	634
Wholesale	**73**	65	67
Other	**464**	234	201
Subtotal	**4,082**	3,324	3,561
Interconnection sales (1)	**380**	244	134
Total Revenue	**$ 4,462**	$ 3,568	$ 3,695

(1) Represents power that is not distributed by Detroit Edison.

Weather, economic factors, competition and electricity prices affect sales levels to customers. Our peak load and highest total system sales generally occur during the third quarter of the year, driven by air conditioning and other cooling-related demands.

Our operations are not dependent upon a limited number of customers, and the loss of any one or a few customers would not have a material adverse effect on Detroit Edison.

Fuel Supply and Purchased Power

Our power is generated from a variety of fuels and is supplemented with purchased power. We expect an adequate supply of fuel and purchased power to meet our obligation to serve customers. Our generating capability is heavily dependent upon the availability of coal. Coal is purchased from various sources in different geographic areas under agreements that vary in both pricing and terms. We expect to obtain the majority of our coal requirements through long-term contracts with the balance to be obtained through short-term agreements and spot purchases. We have several long-term and short-term contracts for a total purchase of approximately 26 million tons of low-sulfur western coal to be delivered from 2006 to 2008. We also have contracts with several suppliers for the purchase of approximately 7 million tons of Appalachian coal to be delivered from 2006 through 2008. These existing long-term coal contracts have fixed prices except for a single contract that has provisions for price escalation as well as de-escalation. We have approximately 90% of our 2006 expected coal requirements under contract. Given the geographic diversity of supply, we believe we can meet our expected generation requirements. We lease a fleet of rail cars and have long-term transportation contracts with companies to provide rail and vessel services for delivery of purchased coal to our generating facilities.

Detroit Edison participates in the energy market through the Midwest Independent System Operator, a Regional Transmission Organization. We offer our generation in the market on a day-ahead and real-time basis and bid for power in the market to serve our load. We are a net purchaser of power which supplements our generation capability to meet customer demand during peak cycles. For example, when high temperatures occur during the summer, we require additional electricity to meet demand. This access to additional power is an efficient and economical way to meet our obligation to customers without increasing capital expenditures to build additional base-load power plants.

Properties

Detroit Edison owns generating plants and facilities that are located in the State of Michigan. Substantially all of our property is subject to the lien of a mortgage. Generating plants owned and in service as of December 31, 2005 are as follows:

Plant Name	Location by Michigan County	Summer Net Rated Capability (1) (2) (MW)	(%)	Year in Service
Fossil-fueled Steam-Electric				
Belle River (3)	St. Clair	1,026	9.2%	1984 and 1985
Conners Creek	Wayne	215	1.9	1951
Greenwood	St. Clair	785	7.1	1979
Harbor Beach	Huron	103	0.9	1968
Marysville	St. Clair	84	0.8	1943 and 1947
Monroe (4)	Monroe	3,115	28.0	1971, 1973 and 1974
River Rouge	Wayne	510	4.6	1957 and 1958
St. Clair	St. Clair	1,415	12.7	1953, 1954, 1959, 1961 and 1969
Trenton Channel	Wayne	730	6.6	1949 and 1968
		7,983	71.8	
Oil or Gas-fueled Peaking Units	Various	1,102	9.9	1966-1971, 1981 and 1999
Nuclear-fueled Steam-Electric Fermi 2 (5)	Monroe	1,111	10.0	1988
Hydroelectric Pumped Storage Ludington (6)	Mason	917	8.3	1973
		11,113	100.0%	

(1) Summer net rated capabilities of generating plants in service are based on periodic load tests and are changed depending on operating experience, the physical condition of units, environmental control limitations and customer requirements for steam, which otherwise would be used for electric generation.

(2) Excludes one oil-fueled unit, St. Clair Unit No. 5 (250 MW), in cold standby status.

(3) The Belle River capability represents Detroit Edison's entitlement to 81.39% of the capacity and energy of the plant. See Note 6.

(4) The Monroe Power Plant provided 38% of Detroit Edison's total 2005 power plant generation.

(5) Fermi 2 has a design electrical rating (net) of 1,150 MW.

(6) Represents Detroit Edison's 49% interest in Ludington with a total capability of 1,872 MW. See Note 6.

Detroit Edison owns and operates 670 distribution substations with a capacity of approximately 32,489,000 kilovolt-amperes (kVA) and approximately 421,000 line transformers with a capacity of approximately 25,345,000 kVA. Circuit miles of distribution lines owned and in service as of December 31, 2005 are as follows:

Electric Distribution Operating Voltage-Kilovolts (kV)	Circuit Miles Overhead	Underground
4.8 kV to 13.2 kV	28,104	13,379
24 kV	101	690
40 kV	2,323	327
120 kV	70	13
	30,598	14,409

There are numerous interconnections that allow the interchange of electricity between Detroit Edison and electricity providers external to our service area. These interconnections are generally owned and operated by ITC and connect to neighboring energy companies.

Regulation

Detroit Edison's business is subject to the regulatory jurisdiction of various agencies, including the MPSC, the FERC and the NRC. The MPSC issues orders pertaining to rates, recovery of certain costs, including the costs of generating facilities and regulatory assets, conditions of service, accounting and operating-related matters. Detroit Edison's MPSC-approved rates charged to customers have historically been designed to allow for the recovery of costs, plus an authorized rate of return on our investments. The FERC regulates Detroit Edison with respect to financing authorization and wholesale electric activities.

The NRC has regulatory jurisdiction over all phases of the operation, construction, licensing and decommissioning of Detroit Edison's nuclear plant operations. We are subject to the requirements of other regulatory agencies with respect to safety, the environment and health.

Since 1996, there have been several important acts, orders, court rulings and legislative actions in the State of Michigan that affect Detroit Edison's operations. In 1996, the MPSC began an initiative designed to give all of Michigan's electric customer's access to electricity supplied by other generators and marketers. In 1998, the MPSC authorized the electric Customer Choice program that allowed for a limited number of customers to purchase electricity from suppliers other than their local utility. The local utility continues to transport the electric supply to the customers' facilities, thereby retaining distribution margins. The electric Customer Choice program was phased in over a three-year period, with all customers having the option to choose their electric supplier by January 2002.

In 2000, the Michigan Legislature enacted legislation that reduced electric rates by 5% and reaffirmed January 2002 as the date for full implementation of the electric Customer Choice program. This legislation also contained provisions freezing rates through 2003 and preventing rate increases for small business customers through 2004 and for residential customers through 2005. The legislation and an MPSC order issued in 2001 established a methodology to enable Detroit Edison to recover stranded costs related to its generation operations that may not otherwise be recoverable due to electric Customer Choice related lost sales and margins. The legislation also provides for the recovery of the costs associated with the implementation of the electric Customer Choice program. The MPSC has determined that these costs will be treated as regulatory assets. Additionally, the legislation provides for recovery of costs incurred as a result of changes in taxes, laws and other governmental actions including the Clean Air Act.

In 2004, the MPSC issued interim and final rate orders that authorized electric rate increases totaling $374 million, and eliminated transition credits and implemented transition charges for electric Customer Choice customers. The increases were applicable to all customers not subject to a rate cap. The interim order affirmed the resumption of the PSCR mechanism for both capped and uncapped customers, which reduced PSCR revenues. The MPSC also authorized the recovery of approximately $385 million in regulatory assets, including stranded costs. As part of the final order Detroit Edison was ordered to file an application to restructure its electric rates.

In February 2005, Detroit Edison filed a rate restructuring proposal with the MPSC to restructure its electric rates and begin phasing out subsidies within the current pricing structure. In December 2005, the MPSC issued an order that provided for initial steps to improve the current competitive imbalance in Michigan's electric Customer Choice program. The December 2005 order establishes cost-based power supply rates for Detroit Edison's full service customers. Electric Customer Choice participants will pay cost-based distribution rates while Detroit Edison's full service commercial and industrial customers will pay cost-based distribution rates that reflect the cost of the residential rate subsidy. Residential customers continue to pay a subsidized below cost rate for distribution service. These revenue neutral revised rates were effective February 1, 2006. Detroit Edison was also ordered to file a general rate case no later than July 1, 2007, based on 2006 actual results.

See Note 4.

Energy Assistance Programs

Energy assistance programs, funded by the federal government and the State of Michigan, remain critical to Detroit Edison's ability to control its uncollectible accounts receivable and collections expenses. Detroit Edison's uncollectible accounts receivable expense is directly affected by the level of government funded assistance its qualifying customers receive. We work continuously with the State of Michigan and others to determine whether the share of funding allocated to our customers is representative of the number of low-income individuals in our service territory.

Strategy and Competition

We strive to be the preferred supplier of electrical generation in southeast Michigan. We can accomplish this goal by working with our customers, communities and regulatory agencies to be a reliable low cost supplier of electricity. To control expenses, we optimize our fuel blends thereby taking maximum advantage of low cost, environmentally friendly low-sulfur western coals. To ensure generation reliability we continue to invest in our generating plants, which will improve both plant availability and operating efficiencies. We also are making capital investments in areas that have a positive impact on reliability and environmental compliance with the goal of high customer satisfaction.

Our distribution operations focus on improving reliability, restoration time and the quality of customer service. We seek to lower our operating costs by improving operating efficiencies. Revenues from year to year will vary due to weather conditions, economic factors, regulatory events and other risk factors as discussed in the "Risk Factors" section that follows.

Effective January 2002, the electric Customer Choice program expanded in Michigan so that all of the Company's electric customers can choose to purchase their electricity from alternative electric suppliers of generation services. Detroit Edison lost 12% of retail sales in 2005, 18% in 2004 and 12% of such sales in 2003 as a result of customers choosing to purchase power from alternative electric suppliers. Customers participating in the electric Customer Choice program consist primarily of industrial and commercial customers whose MPSC-authorized full service rates exceed their cost of service. Customers who elect to purchase their electricity from alternative electric suppliers by participating in the electric Customer Choice program have an unfavorable effect on our financial performance. The effect of lost sales due to the electric Customer Choice program has reduced our need for purchased power and when market conditions are favorable we sell power into the wholesale market, in order to lower costs to full service customers.

Detroit Edison acquires transmission services from ITC, a wholly owned subsidiary of DTE Energy until February 2003. By FERC order, rates charged by ITC to Detroit Edison were frozen through December 2004. Thereafter, rates became subject to normal FERC regulation. With the MPSC's November 2004 final rate order, transmission costs are recoverable through Detroit Edison's PSCR mechanism.

Competition in the regulated electric distribution business is primarily from the on-site generation of industrial customers and from distributed generation applications by industrial and commercial customers. We do not expect significant competition for distribution to any group of customers in the near term.

GAS UTILITY

Description

Our Gas Utility segment consists of MichCon and Citizens, natural gas utilities subject to regulation by the MPSC. MichCon is engaged in the purchase, storage, transmission, distribution and sale of natural gas to approximately 1.3 million residential, commercial and industrial customers in the State of Michigan. MichCon also has subsidiaries involved in the gathering and transmission of natural gas in northern Michigan. MichCon operates one of the largest natural gas distribution and transmission systems in the United States. Citizens distributes natural gas in Adrian, Michigan.

Revenue by Service

(in Millions)	2005	2004	2003
Gas Sales	$ 1,860	$ 1,435	$ 1,242
End User Transportation	134	119	136
Intermediate Transportation	58	56	51
Other	86	72	69
Total Revenue	$ 2,138	$ 1,682	$ 1,498

- *Gas Sales* — Includes the sale and delivery of natural gas primarily to residential and small-volume commercial and industrial customers.
- *End User Transportation* — Gas delivery service provided primarily to large-volume commercial and industrial customers. Additionally, the service is provided to residential customers, and small-volume commercial and industrial customers who have elected to participate in our Customer Choice program. End user transportation customers purchase natural gas directly from producers or brokers and utilize our pipeline network to transport the gas to their facilities or homes.
- *Intermediate Transportation* — Gas delivery service provided to producers, brokers and other gas companies that own the natural gas, but are not the ultimate consumers. Intermediate transportation customers utilize our gathering and high-pressure transmission system to transport the gas to storage fields, processing plants, pipeline interconnections or other locations.
- *Other* — Includes revenues from providing appliance maintenance, facility development, gas storage and other energy-related services.

Our gas sales, end user transportation and intermediate transportation volumes, revenues and net income are impacted by weather. Given the seasonal nature of our business, revenues and net income are concentrated in the first and fourth quarters of the calendar year. By the end of the first quarter, the heating season is largely over, and we typically realize substantially reduced revenues and earnings in the second quarter and losses in the third quarter.

Our operations are not dependent upon a limited number of customers, and the loss of any one or a few customers would not have a material adverse effect on our Gas Utility segment.

Natural Gas Supply

Our gas distribution system has a planned maximum daily send-out capacity of 2.8 Bcf, with approximately 67% of the volume coming from underground storage for 2005. Peak-use requirements are met through utilization of our storage facilities, pipeline transportation capacity, and purchased storage services. Because of our geographic diversity of supply and our pipeline transportation and storage capacity, we are able to reliably meet our supply requirements. We believe natural gas supply and pipeline capacity will be sufficiently available to meet market demands in the foreseeable future.

We purchase natural gas supplies in the open market by contracting with producers and marketers, and we maintain a diversified portfolio of natural gas supply contracts. Supplier, producing region, quantity, and available transportation diversify our natural gas supply base. We obtain our natural gas supply from various sources in different geographic areas (Gulf Coast, Mid-Continent, Canada and Michigan) under agreements that vary in both pricing and terms. Gas supply pricing is generally tied to published price indices to approximate current market prices.

Properties

We own distribution, transmission and storage properties that are located in the State of Michigan. Our distribution system includes approximately 18,000 miles of distribution mains, approximately 1,179,000 service lines and approximately 1,320,000 active meters. We own approximately 2,600 miles of transmission lines that deliver natural gas to the distribution districts and interconnect our storage fields with the sources of supply and the market areas.

We own properties relating to four underground natural gas storage fields with an aggregate working gas storage capacity of approximately 124 Bcf. These facilities are important in providing reliable and cost-effective service to our customers. Most of the company's distribution and transmission property are located on property owned by others and used by the company through easements, permits or licenses. Substantially all of our property is subject to the lien of a mortgage.

We are directly connected to interstate pipelines, providing access to most of the major natural gas producing regions in the Gulf Coast, Mid-Continent and Canadian regions. The company's primary long-term transportation contracts are as follows:

	Availability (MMcf/d)	Contract expiration
Panhandle Eastern Pipeline Company	75	2009
Trunkline Gas Company	10	2009
Viking Gas Transmission Company	50	2010
TransCanada PipeLines Limited	50	2010
Great Lakes Gas Transmission L.P	30	2011
ANR Pipeline Company	245	2011
Vector Pipeline L.P	50	2012

We own 840 miles of transportation and gathering pipelines in the northern lower peninsula of Michigan. We lease a portion of our pipeline system to the Vector Pipeline Partnership (an affiliate) through a capital lease arrangement. See Note 11. We also own a 2,400 horsepower compressor station located in northern Michigan.

Regulation

We are subject to the regulatory jurisdiction of the MPSC, which issues orders pertaining to rates, recovery of certain costs, including the costs of regulatory assets, conditions of service, accounting and other operating-related matters. We are subject to the requirements of other regulatory agencies with respect to safety, the environment and health.

In the late 1990s, the MPSC began an initiative designed to give all of Michigan's natural gas customers added choices and the opportunity to benefit from lower gas costs resulting from competition. In 1999, the MPSC approved a comprehensive experimental three-year gas Customer Choice program that allowed an increasing number of customers to purchase natural gas from suppliers other than their local utility. In December 2001, the MPSC issued an order that continued the gas Customer Choice program on a permanent and expanding basis. The permanent gas Customer Choice program was phased in over a three-year period, with all customers having the option to choose their gas supplier by April 2004. Since MichCon continues to transport and deliver the gas to the participating customer premises at prices comparable to margins earned on gas sales, customers switching to other suppliers have little impact on MichCon's earnings.

In April 2005, the MPSC issued a final rate order which increased MichCon's base rates by $61 million annually effective April 29, 2005. See Note 4.

Energy Assistance Program

Energy assistance programs, funded by the federal government and the State of Michigan, remain critical to MichCon's ability to control its uncollectible accounts receivable and collections expenses. MichCon's uncollectible accounts receivable expense is directly affected by the level of government funded assistance its qualifying customers receive. We work continuously with the State of Michigan and others to determine whether the share of funding allocated to our customers is representative of the number of low-income individuals in our service territory.

Strategy and Competition

Our strategy is to expand our role as the preferred provider of natural gas in Michigan. As a result of more efficient furnaces and appliances, and customer conservation due to high natural gas prices, we expect future sales volumes to remain at current levels or slightly decline. We continue to provide energy-related services that capitalize on our expertise, capabilities and efficient systems. We anticipate revenue growth through increased rates authorized by the MPSC in April 2005. See Note 4. We continue to focus on lowering our operating costs by improving operating efficiencies.

Competition in the gas business primarily involves other natural gas providers, as well as providers of alternative fuels and energy sources. The primary focus of competition in the end user transportation market is cost and reliability. Some large commercial and industrial customers have the ability to switch to alternative fuel sources such as coal, electricity, oil and steam. If these customers were to choose an alternative fuel source, they would not have a need for our end-user transportation service. In addition, some of these customers could bypass our pipeline system and have their gas delivered directly from an interstate pipeline. We compete against alternative fuel sources by providing competitive pricing and reliable service, supported by our extensive storage capacity.

Our extensive transmission pipeline system has enabled us to develop a 600 to 700 Bcf annual market for intermediate transportation services for Michigan gas producers, marketers, distribution companies and other pipeline companies. We operate in a central geographic location with connections to major Mid-western interstate pipelines that extend throughout the Midwest, eastern United States and eastern Canadian markets.

NON-UTILITY OPERATIONS

Power and Industrial Projects

Description

Power and Industrial Projects is comprised of Coal-Based Fuels, On-Site Energy Projects, Non-Utility Power Generation, Landfill Gas Recovery, and Waste Coal Recovery.

Coal-Based Fuels

Coal-based fuels operations include producing synthetic fuel from our nine synfuel plants and producing coke from two coke battery plants. The production of synfuel from all of the synfuel plants and the production of coke from one of the coke battery plants generate production tax credits. Production tax credits are designed to stimulate investment in and development of alternate fuel sources. We have private letter rulings from the IRS for all of our synfuel plants. Production tax credits for synfuel-related facilities and one coke battery expire in 2007. Production tax credits were reinstated for one coke battery for the years 2006 through 2009.

The synthetic fuel process involves chemically modifying and binding particles of coal to produce a fuel that is used for power generation and coke production. Since 2002, we have sold interests in all nine of our synfuel plants, ranging from a 49%-99% share in each, or approximately 91% of our total production capacity. We will continue evaluating opportunities to sell additional interests in our synfuel plants. We consolidate these projects due to our controlling influence and continuing involvement.

The coke battery facilities produce coke that is used in blast furnaces within the steel industry.

(Dollars in Millions)	2005	2004	2003
Production Tax Credits Generated			
Synfuel Plants			
Allocated to DTE Energy	**$ 45**	$ 29	$ 228
Allocated to partners	**562**	411	146
	$ 607	$ 440	$ 374
Coke Batteries:			
Allocated to DTE Energy	**$ 2**	$ 2	$ 3

On-Site Energy Projects

We own and/or operate on-site facilities, including pulverized coal injection, power generation, steam production, chilled water, wastewater treatment, pulverized petroleum coke and compressed air. Many of these facilities deliver utility-type services to industrial, commercial and institutional customers. In 2005, we executed an agreement to purchase five on-site energy projects. The purchase of three of the projects closed in 2005. We expect the purchases of the two remaining projects will close early in 2006. We also began commercial operations of a petroleum coke pulverizing facility located in Vicksburg, Mississippi.

Non-Utility Power Generation

We operate peaking, gas-fired and biomass-fired electric generating plants. We have four natural gas-fired electric generating plants that are located in the Great Lakes region, and in 2005 we acquired a 99% interest in one biomass-fired electric generating plant in California.

Landfill Gas Recovery

We develop, own and operate landfill gas recovery systems in the U.S. Landfill gas, a byproduct of solid waste decomposition, is composed of approximately equal portions of methane and carbon dioxide. We develop landfill gas recovery systems that capture the gas and use it productively. Landfill gas recovery systems provide local utilities, industry and consumers with an opportunity to use a competitive, renewable source of energy. During 2005, we acquired and placed in commercial operation a coal mine gas processing facility in southern Illinois. This processed methane is sold into the natural gas transmission system. Converting the methane into a renewable energy resource conserves fossil fuels. Many of our facilities generate production tax credits that will expire in 2007.

Landfill gas recovery has operations in 13 states.

(Dollars in Millions)	2005	2004	2003
Landfill Sites	**32**	29	31
Gas Produced (in Bcf)	**20.2**	23.2	26.8
Tax Credits Generated (1)	**$ 8.3**	$ 7.7	$ 10.5

(1) DTE Energy's portion of total tax credits generated.

Waste Coal Recovery

We own the rights to a proprietary technology that produces high quality coal products from fine coal slurries that are typically discarded from coal mining operations. The technology produces a fine-coal fuel by removing impurities from waste coal material. The fine-coal fuel can be used in power plants, as a feedstock for synthetic fuel production and for other industrial applications. Our first facility in Ohio became operational in late-2003. Certain problems were encountered in the excavation of the waste material and delivery to the cleaning plant. We are in a testing phase of a proprietary slurry mining system designed to allow us to economically produce a consistent product at a rate of 300,000 tons of fine coal per year.

In late 2005, we completed construction of an “in-line” demonstration waste coal recovery facility at an active coal preparation plant in Virginia. This facility is designed to increase the recovery of high value coal while reducing the amount of discarded waste coal. We are currently conducting preliminary testing. If the demonstration project proves successful, this may lead to additional opportunities for similar projects in 2006.

Properties

The following are significant Coal-Based Fuels properties:

Facility	Location	% Owned	Industry Served
Synthetic Fuels			
DTE Red Mountain, LLC	Tarrant, AL	51%	Foundry Coke/Steel
DTE Belews Creek, LLC	Belews Creek, NC	1%	Utility
DTE Utah Synfuels, LLC	Price, UT	1%	Industrial/Utility
DTE Indy Coke, LLC	Moundsville, WV	1%	Utility
DTE Clover, LLC	Bledsoe, KY	5%	Utility
DTE Smith Branch, LLC	Pineville, WV	1%	Steel/Export
DTE River Hill, LLC	Karthaus, PA	51%	Utility
DTE Buckeye, LLC (2 plants)	Cheshire, OH	1%	Utility
Coke Battery			
EES Coke Battery LLC (1)	River Rouge, MI	51%	Steel
Indiana Harbor Coke Co., LP	East Chicago, IN	5%	Steel

(1) Effective January 1, 2006, we purchased an additional 49% interest in EES Coke Battery LLC.

The following are significant On-Site Energy Projects:

Facility	Location	% Owned	Type
PCI Enterprises	River Rouge, MI	100%	Pulverized Coal
DTE Sparrows Point	Sparrows Point, MD	100%	Pulverized Coal
DTE Northwind	Detroit, MI	100%	Steam and Chilled Water
DTE Moraine	Moraine, OH	100%	Compressed Air
DTE Tonawanda	Tonawanda, NY	100%	Chilled and Waste Water
Metro Energy	Romulus, MI	100%	Electricity, Hot and Chilled Water
Lordstown Energy	Lordstown, OH	100%	Steam, Chilled Water, Compressed Air and Reverse Osmosis Water
Defiance Energy	Defiance, OH	100%	Steam, Cooling Tower Water, Chilled Water, Compressed Air
DTE PetCoke	Vicksburg, MS	100%	Pulverized Petroleum Coke
Mobile Energy Services	Mobile, AL	50%	Electric Generation, Electric Distribution, and Steam
DTE Energy Center	Various sites in MI, IN, OH	50%	Electric Distribution, Chilled Water, Waste Water, Lighting, Compressed Air, Mist and Dust Collectors

The following are significant properties operated by Non-Utility Power Generation:

Facility	Location	% Owned	Capacity (in MW)
DTE Georgetown	Indianapolis, IN	100%	80
DTE River Rouge	River Rouge, MI	100%	240
Crete Energy Ventures	Crete, IL	50%	320
DTE East China	East China Twp, MI	100%	320
Woodland Biomass	Woodland, CA	99%	25
			985

Strategy and Competition

Power and Industrial Projects will continue leveraging its extensive energy-related operating experience and project management capability to develop and grow our on-site energy business. We will continue to evaluate opportunities to sell interests in our two remaining majority-owned synfuel plants in 2006. We also will continue to pursue opportunities to provide asset management and operations services to third parties.

We anticipate building around our core strengths in the markets where we operate. In determining the markets in which to compete, we examine closely the regulatory and competitive environment, the number of competitors and our ability to achieve sustainable margins. We plan to maximize the effectiveness of our inter-related businesses as we expand from our current regional focus. As we pursue growth opportunities, our first priority will be to achieve value-added returns.

We intend to focus on the following areas for growth:

- Optimizing our synfuel portfolio;
- Providing operating services to owners of industrial and power plants;
- Acquiring and developing solid fuel-fired power plants and landfill gas recovery facilities;
- Expanding on-site energy projects; and
- Developing new tax advantaged opportunities.

Landfill gas recovery's strategy capitalizes upon our industry experience of over 15 years. We are evaluating business growth through both development and acquisitions. We compete primarily with fossil fuels such as natural gas and coal. However, we believe the environmental benefits of landfill gas recovery along with reasonable and economic access to landfill sites provide a platform for future growth.

We believe that the waste coal recovery business has the potential to contribute to future earnings and provide significant environmental benefits.

Unconventional Gas Production

Description

Our Unconventional Gas Production business is engaged in natural gas exploration, development and production primarily within the Antrim shale in the northern lower peninsula of Michigan and the Barnett shale in north central Texas. We are experienced in Antrim shale where we manage one of the industry's largest inventories of proved gas shale reserves. We are developing a significant presence in the emerging Barnett shale.

During 2005, we invested $144 million acquiring, testing, developing and producing our Antrim and Barnett shale acreage. In 2005, we added proved reserves of 76 Bcfe in both the Antrim and Barnett shales, resulting in year end total proved reserves of 397 Bcfe. The Barnett shale wells yielded 0.7 Bcfe of production in 2005. Barnett shale leasehold acres increased to 87,804 gross acres (75,994 net of interest of others) primarily through the acquisition of a 100% interest in 44 wells and 18,000 acres in one transaction. We drilled 17 development wells (11.2 net of interest of others) in the Barnett shale acreage with a success rate of 100% in 2005. We also drilled 3 test wells (100% gross and net of interest of others) in an unproved area of the southern portion of our Barnett shale acreage holdings. Testing of the southern acreage is ongoing and will continue in 2006.

Properties

Unconventional Gas Production owns interests in the following producing wells and acreage as of December 31.

	2005		2004		2003	
	Gross	**Net** (1)	Gross	Net (1)	Gross	Net (1)
Producing Wells and Acreage						
Producing Wells						
Antrim shale	**2,010**	**1,630**	1,878	1,523	1,814	1,471
Barnett shale	**65**	**55**	5	1	—	—
	2,075	**1,685**	1,883	1,524	1,814	1,471
Developed Lease Acreage						
Antrim shale	**278,789**	**217,643**	266,064	213,959	262,321	212,067
Barnett shale	**15,524**	**14,367**	1,262	316	—	—
	294,313	**232,010**	267,326	214,275	262,321	212,067
Undeveloped Lease Acreage						
Antrim shale	**86,028**	**73,056**	92,328	79,025	94,866	81,133
Barnett shale	**72,280**	**61,627**	54,530	48,541	4,034	3,156
	158,308	**134,683**	146,858	127,566	98,900	84,289

(1) Excludes the interest of others.

Strategy and Competition

We manage and operate our Antrim and Barnett shale gas properties to maximize returns on investment and increase earnings with the overriding goal of optimizing the cost of producing reserves and adding additional proved reserves. Some of our long-term contracts that fixed the prices of gas sold from production of Antrim shale gas begin to expire in 2006. This will create opportunities to remarket Antrim shale gas production at current higher market rates.

High natural gas prices and the potential for successes within the Barnett shale are resulting in more capital being invested into the region. This competition for opportunities, goods and services increases costs. However, our experience in the Antrim shale and our experienced Barnett shale personnel provide an advantage in addressing potential cost increases.

In 2006, we expect to drill 130 wells in the Antrim shale and 55 wells in the Barnett shale. Combined investment for both areas is expected to be approximately $100 million to $130 million during 2006. Successful testing on unproved acreage may yield additional significant investment opportunities.

Fuel Transportation and Marketing

Description

Fuel Transportation and Marketing consists of the electric and gas marketing and trading operations of DTE Energy Trading, Coal Transportation and Marketing, and the Pipelines, Processing and Storage businesses.

DTE Energy Trading

DTE Energy Trading focuses on physical power and gas marketing and trading, structured transactions, enhancement of returns from DTE Energy's power plants and the optimization of contracted natural gas pipelines and storage capacity positions. Our customer base is predominantly utilities, local distribution companies, large industrials, and other marketing and trading companies. We enter into derivative financial instruments as part of our marketing and hedging activities. Most of the derivative financial instruments are accounted for under the mark-to-market method, which results in earnings recognition of unrealized gains and losses from changes in the fair value of the derivatives. We utilize forwards, futures, swaps and option contracts to mitigate risk associated with our marketing and trading activity as well as for proprietary trading within defined risk guidelines. DTE Energy Trading is integral in providing commodity risk management services to the other unregulated businesses within DTE Energy.

Coal Transportation and Marketing

Coal Transportation and Marketing provides fuel, transportation, and equipment management services tailored to the individual requirements of each customer. We specialize in minimizing fuel costs and maximizing reliability of supply for energy-intensive customers. Our external customers include electric utilities, merchant power producers, integrated steel mills and large industrial companies with significant energy requirements. Additionally, we participate in coal trading, coal-to-power tolling transactions and the purchase and sale of emissions credits. Coal-to-power tolling is another facet of the trading function, where we buy and arrange transportation of coal to a power plant that has excess generating capacity. The plant then burns the coal and produces electricity for a fee and returns it via the grid to DTE Energy Trading, which uses the power to fulfill contracts or meet market needs.

(in Millions)	**2005**	2004	2003
Tons of Coal Shipped (1)	**42**	40	32

(1) Includes intercompany transactions of 20 tons, 18 tons and 14 tons in 2005, 2004 and 2003, respectively.

We also provide rail car equipment management services tailored to the individual requirements of each customer. We operate a number of railcar maintenance and repair facilities in Nebraska and Indiana serving coal transporters, as well as other industries and rail car types.

Pipelines, Processing and Storage

The Pipelines, Processing and Storage business owns and manages a network of natural gas transmission pipelines, storage facilities and gas processing facilities. We have a partnership interest in Vector Pipeline (Vector), an interstate transmission pipeline, which connects Michigan to Chicago and Ontario market centers. We specialize in providing natural gas storage and transportation services in the Midwest and Northeast markets.

Pipelines, Processing and Storage has interests in seven processing plants that extract carbon dioxide from Antrim gas production in northern Michigan, making it suitable for transportation to nearby markets. Additionally, we have storage capacity rights capable of storing up to 75.7 Bcf in natural gas storage fields located in Michigan. The Washington 10 storage facility is a 66 Bcf high deliverability storage field having bi-directional interconnections with Vector Pipeline and MichCon providing customers access to the Chicago, Michigan and Ontario market hubs.

Properties

The assets of these businesses are complementary with other DTE Energy assets. The Pipelines, Processing and Storage business holds the following property:

Property Classification	% Owned	Description	Location
Pipelines			
Vector Pipeline	40%	348-mile pipeline with 1,000 MMcf per day capacity	Midwest
Processing Plants	90%	197 MMcf per day capacity	Northern Michigan
Storage			
Washington 28	50%	9.7 Bcf of storage capacity	Washington Twp, MI
Washington 10	Leased	66 Bcf of storage capacity	Washington Twp, MI

Strategy and Competition

DTE Energy Trading focuses on physical gas, power marketing and structured transactions for large customers, as well as the enhancement of returns from other DTE Energy assets including natural gas production, power plants, and pipeline and storage assets.

Our strategy for our trading business is to deliver value-added services to our customers. We seek to manage this business in a manner consistent with and complementary to the growth of our other business segments. We focus on physical marketing and the optimization of our portfolio of energy assets. We compete with electric and gas marketers, traders, utilities and other energy providers. We have risk management and credit processes to monitor and mitigate risk.

Our Coal Transportation and Marketing business continues to leverage our position as one of the top North American coal marketers and our reputation as an efficient manager of transportation assets. Trends such as railroad and mining consolidation and the lack of certainty in developing new mines by many mining firms could have an impact on how we compete in the future. We will continue to work with suppliers and the railroads to promote secure and competitive access to coal to meet the energy requirements of our customers.

Pipelines, Processing and Storage focuses on asset development opportunities in the Midwest-to-Northeast region to supply natural gas to meet growing demand. We expect much of the growth in the demand for natural gas in the U.S. to occur within the Mid-Atlantic and New England regions. These regions currently lack the pipeline and gas storage infrastructure necessary to deliver gas volumes to meet growing demand. Vector is an interstate pipeline that is filling a large portion of that need, and is complemented by our Michigan storage business. Vector is awaiting FERC approval for a 200 MMcf per day expansion of long-haul capacity scheduled to be in service by November 2007. The Washington 10 storage facility received MPSC approval for a project, which expands working capacity from 51.4 to 66 Bcf. This additional working gas capacity, added to the unutilized working gas capacity previously unavailable due to lack of compression, will create additional high deliverability firm storage service which is expected to be in service by April 2006. Another opportunity is Millennium Pipeline, in which we have a 10.5% interest. Upon finalizing market support and receiving required federal and regulatory approvals, the Millennium Pipeline could be in service by 2007 and would be able to transport up to 500 MMcf per day. The gas supply for Millennium could be sourced from Michigan storage facilities or from Vector Pipeline for consumption by the higher value markets in the Northeast U.S.

CORPORATE & OTHER

Description

Corporate & Other includes various corporate support functions such as accounting, legal and information technology. Because these functions essentially support the entire Company, their costs are allocated to the various segments based on services utilized. Therefore, the effect of the allocation on each segment can vary from year to year. Additionally, Corporate & Other holds certain non-utility debt, assets held for sale and investments in energy related funds.

Strategy and Competition

Our energy related investment strategy is to create a profitable portfolio by investing in companies that facilitate the creation of new businesses, expand growth opportunities for existing businesses or enable performance improvements in our existing businesses. We seek to gain early experience in emerging energy sectors where energy trends and technologies may create potentially profitable opportunities. The investment portfolio consists of direct investments in energy related companies and venture funds.

ENVIRONMENTAL MATTERS

We are subject to extensive environmental regulation. Additional costs may result as the effects of various substances on the environment are studied and governmental regulations are developed and implemented. We expect to continue recovering environmental costs related to utility operations through rates charged to our customers. The following table summarizes our expected significant environmental expenditures:

(in Millions)	Electric	Gas	Non-Utility	Total
Air	$ 2,385	$ —	$ 10	$ 2,395
Water	50	—	15	65
MGP Sites	3	35	—	38
Other Clean Up Sites	10	1	—	11
Estimated total expenditures	$ 2,448	$ 36	$ 25	$ 2,509
Estimated 2006 expenditures	$ 224	$ 5	$ 21	$ 250

Air - Detroit Edison is subject to EPA ozone transport and acid rain regulations that limit power plant emissions of sulfur dioxide and nitrogen oxides. In March 2005, EPA issued additional emission reduction regulations relating to ozone, fine particulate, regional haze and mercury air pollution. The new rules will lead to additional controls on fossil-fueled power plants to reduce nitrogen oxide, sulfur dioxide and mercury emissions. The cost to address environmental air issues is estimated through 2018.

Water - Detroit Edison is required to examine alternatives for reducing the environmental impacts of the cooling water intake structures at several of its facilities. Based on the results of studies to be conducted over the next four to six years, Detroit Edison may be required to install additional control technologies to reduce the environmental impact of the intake structures.

MGP Sites - Prior to the construction of major interstate natural gas pipelines, gas for heating and other uses was manufactured locally from processes involving coal, coke or oil. The facilities, which produced gas for heating and other uses, have been designated as MGP sites. Gas Utility owns, or previously owned, fifteen such former MGP sites. In addition to the MGP sites, the company is also in the process of cleaning up other contaminated sites. As a result of these determinations, we have recorded liabilities related to these sites. Cleanup activities associated with these sites will be conducted over the next several years.

Detroit Edison conducted remedial investigations at contaminated sites, including two MGP sites, the area surrounding an ash landfill and several underground and aboveground storage tank locations. The findings of these investigations indicated that the estimated cost to remediate these sites is expected to be incurred over the next several years.

Non-utility – Our non-utility affiliates are subject to a number of environmental laws and regulations dealing with the protection of the environment from various pollutants. We are in the process of installing new environmental equipment at our coke battery facilities in Michigan. We expect the projects to be completed within two years. Our other non-utility affiliates are substantially in compliance with all environmental requirements.

Greater details on environmental issues are provided in the following Notes to the Consolidated Financial Statements:

Note	Title
4	Regulatory Matters
5	Nuclear Operations
13	Commitments and Contingencies

Item 1A. Company Risk Factors

There are various risks associated with the operations of DTE Energy's utility and non-utility businesses. To provide a framework to understand the operating environment of DTE Energy, we are providing a brief explanation of the more significant risks associated with our businesses. Although we have tried to identify and discuss key risk factors, others could emerge in the future. Each of the following risks could affect our performance.

Our ability to utilize production tax credits may be limited. We have generated production tax credits from our synfuel, coke battery, landfill gas recovery and gas production operations. We have received favorable private letter rulings on all of our synfuel facilities. All production tax credits taken after 2001 are subject to audit by the Internal Revenue Service (IRS). If our production tax credits were disallowed in whole or in part as a result of an IRS audit, there could be additional tax liabilities owed for previously recognized tax credits that could significantly impact our earnings and cash flows. The value of future credits generated may be affected by new tax legislation. Moreover, production tax credits related to generation of synfuels expire at the end of 2007. The combination of IRS audits of production tax credits, supply and demand for investment in credit producing activities and new tax legislation could have an impact on our earnings and cash flows. We have also provided certain guarantees and indemnities in conjunction with the sales of interests in our synfuel facilities.

The value of a production tax credit can vary each year and is adjusted annually by an inflation factor as published by the IRS in April of the following year. Additionally, the value of the production tax credit in a given year is reduced if the Reference Price of oil within the year exceeds a threshold price and is eliminated entirely if the Reference Price exceeds a phase-out price. The Reference Price of a barrel of oil is an estimate of the annual average wellhead price per barrel for domestic crude oil. For 2005, the monthly average wellhead prices were approximately $6 lower than the New York Mercantile Exchange (NYMEX) price for light, sweet crude oil. The 2006 realized and unrealized NYMEX price was $65.08 as of February 28, 2006, equating to an estimated Reference Price of $59, which is within the phase-out range. If during 2006 or 2007, the annual average wellhead price for a barrel of domestic crude oil exceeds the threshold price, our synthetic fuel business would be adversely affected for those years and, depending on the magnitude of increases in oil prices, the adverse effect for that year could be material and could have an impact on our synthetic fuel production plans which, in turn, may have a material impact on our results of operations, cash flow, and financial condition.

Our estimates of gas reserves are subject to change. We cannot assure that our estimates of our Antrim and Barnett gas reserves are accurate. Estimates of proved gas reserves and the future net cash flows attributable to those reserves are prepared by independent engineers. There are numerous uncertainties inherent in estimating quantities of proved gas reserves and cash flows attributable to such reserves, including factors beyond our control and that of our engineers. Reserve engineering is a subjective process of estimating underground accumulations of gas that cannot be measured in an exact manner. The accuracy of an estimate of quantities of reserves, or of cash flows attributable to such reserves, is a function of the available data, assumptions regarding expenditures for future development and exploration activities, and of engineering and geological interpretation and judgment. Additionally, reserves and future cash flows may be subject to material downward or upward revisions, based upon production history, development and exploration activities and prices of gas. Actual future production, revenue, taxes, development expenditures, operating expenses, underlying information, quantities of recoverable reserves and the value of cash flows from such reserves may vary significantly from the assumptions and underlying information we used. In addition, different reserve engineers may make different estimates of reserves and cash flows based on the same available data.

Failure to successfully implement new processes and information systems could interrupt our operations. Our businesses depend on numerous information systems for operations and financial information and billings. DTE2 is a multi-year Company-wide initiative to improve existing processes and implement new core information systems. We launched the first phase of our DTE2 project in 2005. Additional phases of implementation are planned for 2007. Failure to successfully implement new processes and new core information systems could interrupt our operations.

Michigan's electric Customer Choice program is negatively impacting our financial performance . The electric Customer Choice program, as originally contemplated in Michigan, anticipated an eventual transition to a totally deregulated and competitive environment where customers would be charged market-based rates for their electricity. The MPSC has continued to regulate electric rates for our customers, while alternative electric suppliers can charge market-based rates. In addition, such regulated electric rates for certain groups of our customers exceed the cost of service to those customers. Due to distorted pricing mechanisms during the initial period of electric Customer Choice, many commercial customers chose alternative electric suppliers. MPSC rate orders in 2004 and 2005 have removed some of the pricing disparity. Recent higher wholesale electric prices have also resulted in some former electric Customer Choice customers migrating back to Detroit Edison for electric generation service. Even with the electric Customer Choice-related rate relief received in Detroit Edison's 2004 and 2005 orders, there continues to be considerable financial risk associated with the electric Customer Choice program. Electric Customer Choice migration is sensitive to market price and bundled electric service price increases.

***Weather significantly affects operations*.** Deviations from normal hot and cold weather conditions affect our earnings and cash flow. Mild temperatures can result in decreased utilization of our assets, lowering income and cash flow. Damage due to ice storms, tornadoes, or high winds can damage our infrastructure and require us to perform emergency repairs and incur material unplanned expenses. The expenses of storm restoration efforts may not be recoverable through the regulatory process.

We are subject to rate regulation. Electric and gas rates for our utilities are set by the MPSC and the FERC and cannot be increased without regulatory authorization. We may be impacted by new regulations or interpretations by the MPSC, the FERC or other regulatory bodies. New legislation, regulations or interpretations could change how our business operates, impact our ability to recover costs through rate increases or require us to incur additional expenses.

Our non-utility operations may not perform to our expectations. We rely on our non-utility operations for a significant portion of our earnings. If our current and contemplated non-utility investments do not perform at expected levels, we could experience diminished earnings potential and a corresponding decline in our shareholder value.

We rely on cash flows from subsidiaries. Cash flows from our utility and non-utility subsidiaries are required to pay interest expenses and dividends on DTE Energy debt and securities. Should a major subsidiary not be able to pay dividends or transfer cash flows to DTE Energy, our ability to pay interest and dividends would be restricted.

Adverse changes in our credit ratings may negatively affect us. Increased scrutiny of the energy industry and regulatory changes, as well as changes in our economic performance, could result in credit agencies reexamining our credit rating. While credit ratings reflect the opinions of the credit agencies issuing such ratings and may not necessarily reflect actual performance, a downgrade in our credit rating could restrict or discontinue our ability to access capital markets at attractive rates and increase our borrowing costs. In addition, a reduction in credit rating may require us to post collateral related to various trading contracts, which would impact our liquidity.

Regional and national economic conditions can have an unfavorable impact on us. Our businesses follow the economic cycles of the customers we serve. Should national or regional economic conditions decline, reduced volumes of electricity and gas we supply will result in decreased earnings and cash flow. Economic conditions in our service territory also impact our collections of accounts receivable and financial results.

Environmental laws and liability may be costly. We are subject to numerous environmental regulations. These regulations govern air emissions, water quality, wastewater discharge, and disposal of solid and hazardous waste. Compliance with these regulations can significantly increase capital spending, operating expenses and plant down times. These laws and regulations require us to seek a variety of environmental licenses, permits, inspections and other regulatory approvals. We may also incur liabilities as a result of potential future requirements to address the climate change issue. The regulatory environment is subject to significant change; therefore, we cannot predict how future issues may impact the company.

Additionally, we may become a responsible party for environmental clean up at sites identified by a regulatory body. We cannot predict with certainty the amount and timing of future expenditures related to environmental matters because of the difficulty of estimating clean up costs. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on potentially responsible parties.

Since there can be no assurances that environmental costs may be recovered through the regulatory process, our financial performance may be negatively impacted as a result of environmental matters.

Operation of a nuclear facility subjects us to risk. Ownership of an operating nuclear generating plant subjects us to significant additional risks. These risks include among others, plant security, environmental regulation and remediation, and operational factors that can significantly impact the performance and cost of operating a nuclear facility. While we maintain insurance for various nuclear-related risks, there can be no assurances that such insurance will be sufficient to cover our costs in the event of an accident or business interruption at our nuclear generating plant, which may affect our financial performance.

The supply and price of fuel and other commodities may impact our financial results. We are dependent on coal for much of our electrical generating capacity. Price fluctuations and fuel supply disruptions could have a negative impact on our ability to profitably generate electricity. Our access to natural gas supplies is critical to ensure reliability of service for our utility gas customers. We have hedging strategies in place to mitigate negative fluctuations in commodity supply prices, but there can be no assurances that our financial performance will not be negatively impacted by price fluctuations. The price of natural gas also impacts the market for other non-utility businesses that compete with utilities and alternative electric suppliers.

A work interruption may adversely affect us. Unions represent approximately 5,800 of our employees. A union choosing to strike as a negotiating tactic would have an impact on our business. We are unable to predict the effects a work stoppage would have on our costs of operation and financial performance.

Unplanned power plant outages may be costly. Unforeseen maintenance may be required to safely produce electricity or comply with environmental regulations. As a result of unforeseen maintenance, we may be required to make spot market purchases of electricity that exceed our costs of generation. Our financial performance may be negatively affected if we are unable to recover such increased costs.

Our ability to access capital markets at attractive interest rates is important. Our ability to access capital markets is important to operate our businesses. Heightened concerns about the energy industry, the level of borrowing by other energy companies and the market as a whole could limit our access to capital markets. Changes in interest rates could increase our borrowing costs and negatively impact our financial performance.

Michigan tax reform may be costly. We are a significant taxpayer in the State of Michigan. Should the legislature change the tax laws, we could face increased taxes.

We may not be fully covered by insurance. While we have a comprehensive insurance program in place to provide coverage for various types of risks, catastrophic damage as a result of acts of God, terrorism, war or a combination of significant unforeseen events could impact our operations and economic losses might not be covered in full by insurance.

Terrorism could affect our business. Damage to downstream infrastructure or our own assets by terrorism would impact our operations. We have increased security as a result of past events and further security increases are possible.

Our participation in energy trading markets subjects us to additional risk . Events in the energy trading industry have increased the level of scrutiny on the energy trading business and the energy industry as a whole. In certain situations we may also be required to post collateral to support trading operations. We have established risk policies to manage the business.

EMPLOYEES

The following table shows our employees as of December 31, 2005 :

	Represented	Non-represented	Total
Detroit Edison	3,961	4,019	7,980
MichCon	1,501	797	2,298
Other	309	823	1,132
Total	5,771	5,639	11,410

There are several bargaining units for our represented employees. Approximately 4,590 of our represented employees are under three-year contracts that expire in 2007. The contracts of the remaining represented employees expire in 2008 and 2009.

EXECUTIVE OFFICERS OF DTE ENERGY

Name	Age (1)	Present Position	Present Position Held Since
Anthony F. Earley, Jr.	56	Chairman of the Board and Chief Executive Officer	8-1-98
Gerard M. Anderson	47	Chief Operating Officer and President	10-31-05
			6-23-04
Stephen E. Ewing	61	Vice Chairman, DTE Energy	10-31-05
		President and Chief Operating Officer, MichCon	4-28-05
Robert J. Buckler	56	President and Chief Operating Officer, Detroit Edison	10-31-05
		Group President, DTE Energy	5-31-05
David E. Meador	48	Executive Vice President and Chief Financial Officer	6-23-04
Lynne Ellyn	54	Senior Vice President and Chief Information Officer	12-31-01
Paul C. Hillegonds	56	Senior Vice President	5-16-05
Ron A. May	54	Senior Vice President	1-22-04
Bruce D. Peterson	49	Senior Vice President and General Counsel	6-25-02
Peter B. Oleksiak	39	Controller	12-05-05
Sandra K. Ennis	49	Corporate Secretary	8-4-05

(1) As of December 31, 2005

Under our Bylaws, the officers of DTE Energy are elected annually by the Board of Directors at a meeting held for such purpose, each to serve until the next annual meeting of directors or until their respective successors are chosen and qualified. With the exception of Messrs. Ewing, Hillegonds, Peterson and Ms. Ellyn, all of the above officers have been employed by DTE Energy in one or more management capacities during the past five years.

Stephen E. Ewing was elected Vice Chairman of DTE Energy on October 31, 2005 and President and Chief Operating Officer of MichCon on April 28, 2005. He previously served as group president for DTE Energy Gas since May 31, 2001. He joined DTE Energy having previously served as president and chief operating officer of MCN Energy and president and chief executive officer of MichCon during the previous five years.

Paul C. Hillegonds was elected Senior Vice President effective May 16, 2005. Mr. Hillegonds was president of Detroit Renaissance for eight years prior to joining DTE Energy.

Bruce D. Peterson was elected Senior Vice President and General Counsel on June 25, 2002. Mr. Peterson was a partner with Hunton & Williams in Washington, D.C. prior to joining DTE Energy.

Lynne Ellyn was elected Senior Vice President and Chief Information Officer on December 31, 2001. Ms. Ellyn returned to DTE Energy after spending a year serving as chief information officer of the San Francisco-based Organic Online Internet media services company. She originally joined DTE Energy in 1998 as vice president, information systems.

Pursuant to Article VI of our Articles of Incorporation, directors of DTE Energy will not be personally liable to the Company or its shareholders in the performance of their duties to the full extent permitted by law.

Article VII of our Articles of Incorporation provides that each current or former director or officer of DTE Energy, or each current and former employee or agent of the Company or a director, officer, employee or agent of another corporation, partnership, joint venture, trust or other enterprise (including the heirs, executors, administrators or estate of such person), shall be indemnified by the Company to the full extent permitted by the Michigan Business Corporation Act or any other applicable laws as presently or hereafter in effect. In addition, we have entered into indemnification agreements with all of our officers and directors; these agreements set forth procedures for claims for indemnification as well as contractually obligating us to provide indemnification to the maximum extent permitted by law.

We and our directors and officers in their capacities as such are insured against liability for alleged wrongful acts (to the extent defined) under seven insurance policies providing aggregate coverage in the amount of $165 million.

Item 3. Legal Proceedings

We are involved in certain legal, regulatory, administrative and environmental proceedings before various courts, arbitration panels and governmental agencies concerning matters arising in the ordinary course of business. These proceedings include certain contract disputes, environmental reviews and investigations, audits, inquiries from various regulators, and pending judicial matters. We cannot predict the final disposition of such proceedings. We regularly review legal matters and record provisions for claims that are considered probable of loss. The resolution of pending proceedings is not expected to have a material effect on our operations or financial statements in the period they are resolved.

In June 2005, Detroit Edison was named as one of approximately 21 defendant utility companies in a class action lawsuit filed in the Superior Court of Justice in Ontario, Canada. Detroit Edison has not been served with this lawsuit. The plaintiffs, a class comprised of current and prior residents living in Ontario (and their respective family members and/or heirs), claim that the defendants emitted and continue to emit pollutants that have harmed the plaintiffs. As a result, the plaintiffs are seeking damages (in Canadian dollars) of approximately $49 billion for alleged negligence, approximately $4 billion per year until the defendants cease emitting pollutants, punitive and exemplary damages of $1 billion, and such other relief as the court deems appropriate. Detroit Edison is not able to predict or assess the outcome of this lawsuit at this time.

For additional discussion on legal matters, see the following Notes to the Consolidated Financial Statements:

Note	Title
4	Regulatory Matters
5	Nuclear Operations
13	Commitments and Contingencies

Item 4. Submission of Matters to a Vote of Security Holders

We did not submit any matters to a vote of security holders in the fourth quarter of 2005.

Part II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our common stock is listed on the New York Stock Exchange, which is the principal market for such stock, and the Chicago Stock Exchange. The following table indicates the reported high and low sales prices of our common stock on the Composite Tape of the New York Stock Exchange and dividends paid per share for each quarterly period during the past two years:

Calendar	Quarter	High	Low	Dividends Paid Per Share
2005				
	First	**$ 46.99**	**$ 42.40**	**$ 0.515**
	Second	**$48.31**	**$ 44.40**	**$ 0.515**
	Third	**$48.22**	**$ 44.11**	**$ 0.515**
	Fourth	**$ 46.65**	**$41.39**	**$ 0.515**
2004				
	First	$42.29	$37.92	$0.515
	Second	$41.58	$37.88	$0.515
	Third	$42.21	$39.31	$0.515
	Fourth	$45.49	$ 41.44	$0.515

At December 31, 2005, there were 177,814,429 shares of our common stock outstanding. These shares were held by a total of 94,981 shareholders of record.

Our Bylaws nullify Chapter 7B of the Michigan Business Corporation Act (Act). This Act regulates shareholder rights when an individual's stock ownership reaches 20% of a Michigan corporation's outstanding shares. A shareholder seeking control of the Company cannot require our Board of Directors to call a meeting to vote on issues related to corporate control within 10 days, as stipulated by the Act. See Note 8 – Common Stock and Earnings Per Share for information concerning the Shareholders' Rights Agreement.

We paid cash dividends on our common stock of $360 million in 2005, $354 million in 2004 and $346 million in 2003. The amount of future dividends will depend on our earnings, cash flows, financial condition and other factors that are periodically reviewed by our Board of Directors. Although there can be no assurances, we anticipate paying dividends at the current rate of $0.515 per quarter for the foreseeable future.

All of our equity compensation plans that provide for the annual awarding of stock-based compensation have been approved by shareholders. See Note 15 — Stock Based Compensation for additional detail. See the following table for information as of December 31, 2005.

	Number of securities to be issued upon exercise of outstanding options	Weighted-average exercise price of outstanding options	Number of securities remaining available for future issuance under equity compensation plans
Plans approved by shareholders	6,236,343	$ 41.31	6,270,941

Item 6. Selected Financial Data

The following selected financial data should be read with the accompanying Management's Discussion and Analysis and Notes to the Financial Statements.

(in Millions, except per share amounts)	2005	2004	2003	2002	2001(1)
Operating Revenues	**$ 9,022**	$ 7,071	$ 7,005	$ 6,694	$ 5,771
Net Income (Loss)					
Total from continuing operations	**$ 576**	$ 461	$ 494	$ 599	$ 317
Discontinued operations	**(36)**	(30)	54	33	12
Cumulative effect of accounting changes	**(3)**	—	(27)	—	3
Net Income	**$ 537**	$ 431	$ 521	$ 632	$ 332
Diluted Earnings Per Share					
Total from continuing operations	**$ 3.27**	$ 2.66	$ 2.93	$ 3.63	$ 2.06
Discontinued operations	**(.20)**	(.17)	.32	.20	.08
Cumulative effect of accounting changes	**(.02)**	—	(.16)	—	.02
Diluted Earnings Per Share	**$ 3.05**	$ 2.49	$ 3.09	$ 3.83	$ 2.16
Financial Information					
Dividends declared per share of common stock	**$ 2.06**	$ 2.06	$ 2.06	$ 2.06	$ 2.06
Total assets	**$ 23,335**	$ 21,297	$ 20,753	$ 19,985	$ 19,587
Long-term debt, including capital leases	**$ 7,080**	$ 7,606	$ 7,669	$ 7,803	$ 7,928
Shareholders' equity	**$ 5,769**	$ 5,548	$ 5,287	$ 4,565	$ 4,589

(1) Includes the acquisition of the Gas Utility business and other non-utility gas businesses on May 31, 2001.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

OVERVIEW

DTE Energy is a growing and diversified energy company with 2005 revenues in excess of $9 billion and approximately $23 billion in assets. Since 2003, our asset base has increased by 12% and operating revenues have grown by 29%.

We are the parent company of Detroit Edison and MichCon, regulated electric and gas utilities engaged primarily in the business of providing electricity and natural gas sales and distribution services throughout southeastern Michigan. We operate three energy-related non-utility segments with operations throughout the United States.

In 2005, our utilities and Power and Industrial Projects segment generated most of our earnings. The improvement in earnings was due to rate increases at our Michigan utilities, favorable weather and continued asset gains from the synthetic fuel business. Earnings were also impacted by mark-to-market losses in our Fuel Transportation and Marketing segment and losses from discontinued operations.

Our 2005 financial performance improved over 2004. The following table summarizes our income since 2003:

(in millions, except Earnings per Share)

	2005	2004	2003
Net Income	**$ 537**	$ 431	$ 521
Earnings per Diluted Share	**$ 3.05**	$ 2.49	$ 3.09
Excluding Discontinued Operations and Accounting Changes			
Income from Continuing Operations	**$ 576**	$ 461	$ 494
Earnings per Diluted share	**$3.27**	$2.66	$2.93

The items discussed below influenced our 2005 financial performance and may affect future results:

- Effects of weather and accounts receivable on utility operations;
- Electric rate orders, electric Customer Choice program, and coal and uranium supply;
- Gas rate and gas cost recovery orders and gas supply;
- Synfuel-related earnings and the impact of higher oil prices on production credit phase-outs;
- Investments in our unconventional gas production business;
- Mark-to-market losses in our Fuel Transportation and Marketing business; and
- Cost reduction efforts and required capital investment.

UTILITY OPERATIONS

Weather - Earnings at our utility operations are seasonal and very sensitive to weather. Electric utility earnings are dependent on hot summer weather, while the gas utility's results are dependent on cold winter weather. The following table explains the impact of weather relative to 30-year historical normal weather temperatures for each utility.

(Dollars in Millions) Year	Percentage change from Normal (1) Electric Utility	Gas Utility	Estimated effect on Net Income Electric Utility	Gas Utility	Total
2005	**47%**	**(3)%**	**$ 63**	**$ (4)**	**$ 59**
2004	(17)%	(4)%	$ (40)	$ (9)	$ (49)
2003	(13)%	2%	$ (24)	$ 3	$ (21)

(1) Electric Utility is based on cooling degree days and the Gas Utility is based on heating degree days.

The positive impact of warmer weather was partially mitigated by the rate cap on residential customers which prevented us from passing through increased generation and purchased power costs incurred to serve the higher demand. Additionally, we occasionally experience various types of storms that damage our electric distribution infrastructure resulting in power outages. Restoration and other costs associated with storm-related power outages lowered pretax earnings by $82 million in 2005, $48 million in 2004 and $72 million in 2003.

Receivables - Both utilities continue to experience high levels of past due receivables, especially within our Gas Utility operations. The increase is attributable to economic conditions, high natural gas prices and the lack of adequate levels of assistance for low-income customers.

We have taken aggressive actions to reduce the level of past due receivables including, increased customer disconnections, contracting with collection agencies and working with the State of Michigan and others to increase the share of low-income funding allocated to our customers. In 2005, we sold previously written-off accounts of $187 million resulting in a gain and net proceeds of $6 million. The gain was recorded as a recovery through bad debt expense, which is included within operation and maintenance expense. As a result of these factors, our allowance for doubtful accounts expense for the two utilities decreased to $98 million in 2005 from $105 million in 2004.

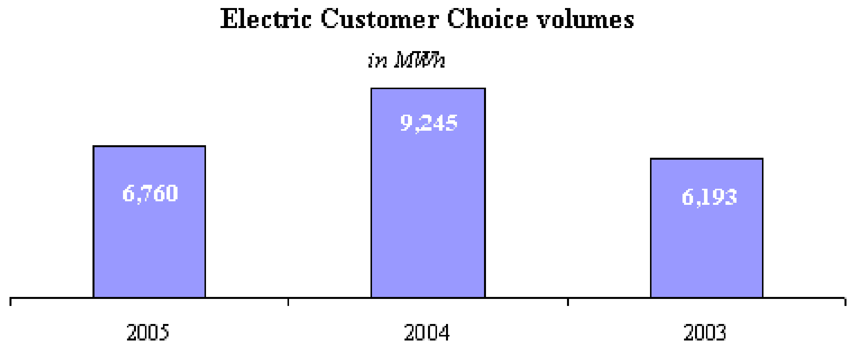
The April 2005 MPSC gas rate order provided for an uncollectible tracking mechanism for MichCon. We will file an annual application comparing our actual uncollectible expense to our designated revenue recovery of approximately $37 million. Ninety percent of the difference from the date of the order will be refunded or surcharged after an annual reconciliation proceeding before the MPSC.

Electric Utility

Electric rate orders — In 2004, the MPSC issued interim and final rate orders that authorized electric rate increases totaling $374 million, eliminated transition credits and implemented transition charges for electric Customer Choice customers. The increases were applicable to all customers not subject to a rate cap. The MPSC also authorized the recovery of approximately $385 million in regulatory assets, including stranded costs. As a result of increased rates, our 2005 pretax margins were higher by $116 million.

Electric Customer Choice - Our customers have the option of participating in the electric Customer Choice program where they can select an alternative electric supplier. Due to distorted pricing mechanisms during the initial period of electric Customer Choice, many commercial customers chose alternative electric suppliers. The impact of the final rate order in 2004, that increased base rates including the recovery of lost margins and transition charges, combined with recent higher wholesale electric prices has resulted in many former electric Customer Choice customers migrating back to Detroit Edison for electrical generation service, partially mitigating the financial impact of the electric Customer Choice program.

The return of customers from the electric Customer Choice program resulted in higher gross margins during 2005. The following graph depicts the electric Customer Choice volumes:



We continue to work with the MPSC to address issues associated with the electric Customer Choice program. In February 2005, we filed a revenue-neutral rate restructuring proposal with the MPSC designed to adjust rates for each customer class to be reflective of the full costs incurred to service such customers. In December 2005, the MPSC issued an order that took some initial steps to improve the current competitive imbalance in Michigan's electric Customer Choice program. The December 2005 order establishes cost-based power supply rates for Detroit Edison's full service customers. Electric Customer Choice participants will pay cost-based distribution rates, while Detroit Edison's full service commercial and industrial customers will pay cost-based distribution rates that reflect the cost of the residential rate subsidy. Residential customers pay a subsidized below cost rate for distribution service. These revenue neutral revised rates were effective February 1, 2006.

Coal Supply – Our generating fleet produces in excess of 70% of its electricity from coal. Increasing coal demand from domestic and international markets has resulted in significant price increases. In addition, difficulty in recruiting workers, obtaining environmental permits and finding economically recoverable amounts of new coal has resulted in decreasing coal output from the central Appalachian region. Furthermore, as a result of environmental regulation and declining eastern coal stocks, demand for cleaner burning western coal has increased. This increased demand for western coal has also resulted in a corresponding demand for western rail shipping, straining railroad capacity, resulting in longer lead times for western coal shipments.

Uranium Supply - We operate one nuclear facility that undergoes a periodic refueling outage approximately every eighteen months. Uranium prices have been rising due to supply concerns. In the future, there may be additional nuclear facilities constructed in the industry that may place additional pressure on uranium supplies and prices.

Gas Utility

Gas final rate order – In April 2005, the MPSC issued a final rate order authorizing MichCon to earn a rate of return on common equity of 11% based on a 50% debt and 50% equity capital structure. Highlights of the order include:

- $61 million increase in annual base rates;
- base rate increase includes $25 million to recover safety and training costs;
- deferral as a regulatory liability for the non-capitalized portion of negative pension expense; and
- adoption of a tracking mechanism for uncollectible accounts receivable.

The final rate order from the MPSC denied recovery or required accounting impairment for the following items:

- $25 million of allocated merger interest from DTE Energy related to the acquisition of MCN Energy;
- $6 million of internal labor and legal costs to remediate MGP sites;
- $5 million as a result of a change to the allocation of historical MGP insurance proceeds;

- $6 million of computer equipment and related depreciation; and
- $42 million impairment related to 90% of the cost of a computer billing system in place prior to DTE Energy's acquisition of MCN Energy. This impairment had a minimal earnings impact on DTE Energy because a valuation allowance was established for this asset at the time of the MCN acquisition in 2001.

Additionally, the rate order adjusted MichCon's depreciation rates and the related revenue requirements with no resulting impact on net income.

Gas cost recovery order – Based on rate orders in place for 2001 and 2002, we filed a gas cost recovery case in 2002 and recorded a $26 million regulatory asset related to unbilled volumes as of December 31, 2001. Over time we recorded $3 million of interest associated with this regulatory asset. In its April 28, 2005 order, the MPSC disallowed recovery and we recorded the impact of the disallowance in the first quarter of 2005.

Natural Gas Supply – Increased demand from natural gas power plants, 2005 hurricane related supply disruptions, regulatory constraints and limited exploration have combined to strain existing natural gas supplies and caused substantial increases in prices.

NON-UTILITY OPERATIONS

We anticipate significant investment opportunities within our non-utility businesses. We employ disciplined investment criteria when assessing opportunities that will leverage our existing assets, skill and expertise. Specifically, we invest in targeted energy markets with attractive competitive dynamics where meaningful scale is in alignment with our risk profile. Assuming no phase-out of production tax credits, the source of investment capital is the estimated cumulative $1.2 billion we anticipate from synfuel cash flow which consists of cash from operations, asset sales, and the utilization of current and previously earned production tax credits to reduce tax payments. Tax credit carryforward utilization in part could be extended past 2008, if taxable income is reduced from current forecasts. However, if oil prices remain at current levels or continue to increase, the estimated cash flow from the synfuel business would be significantly less and would adversely impact the success of this strategy, unless we identify alternative sources of cash.

Power and Industrial Projects

We anticipate building around our core strengths in the markets where we operate. In determining the markets in which to compete, we closely examine the regulatory environment, the number of competitors and our ability to achieve sustainable margins. We plan to maximize the effectiveness of our inter-related businesses as we expand from our current regional focus. As we pursue growth opportunities, our first priority will be to achieve value-added returns.

We plan to focus on the following areas for growth:

- Optimizing the remaining life of our synfuel portfolio;
- Providing operating services to owners of industrial and power plants;
- Acquiring and developing solid fuel-fired power plants;
- Expanding on-site energy projects; and
- Developing new tax advantaged opportunities.

Synfuel-related earnings — We operate nine synthetic fuel production plants throughout the United States. Synfuel plants chemically change coal into a synthetic fuel as determined under the Internal Revenue Code. Production tax credits are provided for the production and sale of solid synthetic fuel produced from coal. These tax credits expire on December 31, 2007. Our synthetic fuel plants generate operating losses which are offset by the resulting production tax credits. We have not had sufficient taxable income to fully utilize production tax credits earned in prior periods. As of December 31, 2005, we have $484 million in tax credit carry-forwards.

To optimize income and cash flow from our synfuel operations, we have sold interests in all nine of our facilities, representing 91% of our total production capacity as of December 31, 2005. We will continue to evaluate opportunities to sell additional interests in our two remaining majority-owned plants. Proceeds from the sales are contingent upon production levels and the value of such credits. When we sell an interest in a synfuel project, we recognize the gain as the facility produces and sells synfuel and when there is persuasive evidence that the sales proceeds have become fixed or determinable and collectibility is reasonably assured. In substance, we are receiving synfuel gains and reduced operating losses in exchange for tax credits associated with the projects sold. Sales of interests in synfuel projects allow us to accelerate cash flow while maintaining a stable income base.

The value of a production tax credit can vary each year and is adjusted annually by an inflation factor as published by the IRS in April of the following year. The value of the production tax credit in a given year is reduced if the Reference Price of oil within the year exceeds a threshold price and is eliminated entirely if the Reference Price exceeds a phase-out price. The Reference Price of a barrel of oil is an estimate of the annual average wellhead price per barrel for domestic crude oil. During 2005, the monthly average wellhead prices were approximately $6 lower than the New York Mercantile Exchange (NYMEX) price for light, sweet crude oil. The actual or estimated Reference Price and beginning and ending phase-out prices per barrel of oil for 2004 through 2007 are as follows:

	Reference Price	Beginning Phase-Out Price	Ending Phase-Out Price
2004 (actual)	$36.75	$ 51.35	$ 64.46
2005 (estimated)	$51	$ 53	$ 66
2006 (estimated)	Not Available	$ 53	$ 67
2007 (estimated)	Not Available	$ 54	$ 68

Recent events have increased domestic crude oil prices, including hurricane-related supply disruptions and continued worldwide demand. Through December 31, 2005, the NYMEX daily closing price of a barrel of oil for 2005 averaged approximately $57, which due to the uncertainty of the wellhead/NYMEX difference, is comparable to an approximate $51 Reference Price. For the remaining life of the tax credits, if the Reference Price falls within or exceeds the phase-out range, the availability of production tax credits in that year would be reduced or eliminated. Any actual tax credit phase-out for 2006 and available tax credits, if any, will not be certain until published by the IRS in April 2007. As of February 28, 2006, the realized and unrealized NYMEX daily closing price of a barrel of oil was $65.08, equating to an estimated Reference Price of $59, which is within the phase-out range. If prices remain at this level throughout 2006, we would experience a phase-out of the production tax credits and our synthetic fuel business would be adversely affected; this could have an impact on our synthetic fuel production plans which, in turn, may have a material adverse impact on our results of operations, cash flow, and financial condition. However, we cannot predict with any certainty the Reference Price for 2006 or beyond.

There is legislation pending in Congress that may impact the potential phase-out of production tax credits for 2006 and 2007. The legislation would use the prior year oil price to determine the current year Reference Price. We are unable to predict the outcome of this legislation.

The gain from the sale of synfuel facilities is comprised of fixed and variable components. The fixed component represents note payments of principal and interest, is not subject to refund, and is recognized as a gain when earned and collectibility is assured. The variable component is based on an estimate of tax credits allocated to our partners, is subject to refund based on the annual oil price phase-out, and is recognized as a gain only when the probability of refund is considered remote and collectibility is assured. Additionally, based on estimates of tax credits allocated, our partners reimburse us (through the project entity) for the operating losses of the synfuel facilities. In the event that the tax credit is phased out, we are contractually obligated to refund to our partners all or a portion of the operating losses funded by our partners. To assess the probability of refund, we use valuation and analysis models that calculate the probability of surpassing the estimated lower band of the phase-out range for the Reference Price of oil for the year. Due to the rise in oil prices, there was a possibility that the 2005 Reference Price of oil could have reached the threshold at which production tax credits would have begun to phase-out. We deferred all variable gains for the first three quarters of 2005. However, in the fourth quarter of 2005, when there was persuasive evidence that the Reference Price of oil would not surpass the estimated lower band of the phase-out range, we recognized all the variable gains related to 2005, of which $167 million (pre-tax) were attributable to the first three quarters of 2005.

Due to changes in the agreements with certain of our synfuel partners and the exercise of existing rights by other of our synfuels partners, a higher percentage of the expected payments in 2006 may be variable note payments. As a result, a larger portion of the 2006 synfuel payments may be subject to refund should a phase-out occur. We will likely defer recognition of the quarterly variable and certain indemnified fixed note payments in 2006 until the probability of refund is remote and collectibility is assured.

As discussed in Note 12, we have entered into derivative and other contracts to economically hedge a portion of our 2006 and 2007 synfuel cash flow exposure related to the risk of oil prices increasing. The derivative contracts are marked to market with changes in fair value recorded as an adjustment to synfuel gains. We recorded a pretax mark to market gain of $48 million during 2005. As part of our synfuel-related risk management strategy, we continue to evaluate alternatives available to mitigate unhedged exposure to oil price volatility. These contracts, and other actions we can take and have taken, will protect approximately 53% of our 2006 cash flow and 31% of our 2007 cash flow. As our risk management position changes due to market volatility or legislative actions, we may adjust our hedging strategy in response to changing conditions.

In addition to entering into economic hedges, we can mitigate our exposure to a tax credit phase-out by shutting down or reducing production at our synfuel facilities, which decreases the amount of operating losses we generate. We regularly monitor oil prices and have created contingency plans to cease synfuel production.

Assuming no synfuel tax credit phase-out, we expect cash flow from our synfuel business will be approximately $1.2 billion from 2006 to 2008. If prices remain at current levels or increase throughout 2006, synfuel production levels may be reduced, which would reduce the income and cash flow from this business. If the Reference Price results in a complete phase out of the synfuel tax credits for 2006, and assuming the previously discussed current level of economic hedges and an early cessation of synfuel production to avoid operating losses, there is a potential negative impact to net income and cash flow of $160 million and $140 million, respectively, before any potential asset impairment and goodwill write-off.

Unconventional Gas Production

During the past year, natural gas prices have reached historically high levels. These high prices provide attractive opportunities for our Unconventional Gas Production business segment. We are an experienced operator with 15 years of experience in the Antrim shale in northern Michigan, and we recently expanded our operations in the Barnett shale basin in north central Texas. Recent leasehold acquisitions have increased our total leasehold acreage to 452,621 acres (366,693 net of interest of others). Over the next few years, our goal is to expand our existing leasehold acreage position and transform unproved acreage into proved reserves.

Antrim shale – We plan to grow through the extension of existing producing areas and acquisition of other producer’s properties. Additionally, we intend to develop existing acreage using the latest horizontal drilling techniques and to continue to search for expansion acreage. Some of our long-term fixed-price obligations for production of Antrim gas begin to expire in 2006. This will create opportunities to remarket Antrim production at significantly higher current market rates.

Michigan – Antrim Shale	2005	2004	2003
Net Producing Wells	**1,630**	1,523	1,471
Production Volume (Bcfe)	**21.5**	22.5	23.2
Proved Reserves (Bcfe)	**338.4**	335.4	351.9
Net Developed Acreage	**217,643**	213,959	212,067
Net Undeveloped Acreage	**73,056**	79,025	81,133
Capital Expenditures (in millions)	**$ 37**	$ 22	$ 26
Future Net Cash Flows (in millions) (1)	**$ 1,307**	$ 760	$ 485
Average gas price with hedges (per Mcf)	**$ 3.10**	$ 3.10	$ 2.97
Average gas price without hedges(per Mcf) (2)	**$ 7.73**	$ 5.57	$ 4.98

(1) Represents the standardized measure of discounted future net cash flows as calculated by an independent engineering firm utilizing extensive estimates. The estimated future net cash flow computations should not be considered to represent our estimate of the expected revenues or the current value of existing proved reserves and do not include the impact of hedge contracts.

(2) The gas produced in the Antrim shale is subject to hedges that begin to expire in 2006. In 2006, we expect to remarket 2.0 Bcf at current market pricing. For 2007, we anticipate remarketing an additional 1.8 Bcf.

Barnett shale - We anticipate significant opportunities in our existing Barnett shale acreage and expect continued extension of producing areas within the Fort Worth Basin. We are currently in the test and development phase for unproved and recently acquired Barnett shale acreage. We plan to increase our acreage through small negotiated acquisitions to build scale.

Texas – Barnett Shale	2005	2004	2003
Net Producing Wells	**55**	1	—
Production Volume (Bcfe)	**0.7**	—	—
Proved Reserves (Bcfe)	**58.6**	7.9	—
Net Developed Acreage	**14,637**	316	—
Net Undeveloped Acreage	**61,627**	48,541	3,156
Capital Expenditures (in millions)	**$ 107**	$ 16	$ 2
Future Net Cash Flows (in millions) (1)	**$ 127**	$ 7	—
Average gas price (per Mcf)	**$ 9.01**	$ 5.70	—

(1) Represents the standardized measure of discounted future net cash flows as calculated by an independent engineering firm utilizing extensive estimates. The estimated future net cash flow computations should not be considered to represent our estimate of the expected revenues or the current value of existing proved reserves and do not include the impact of hedge contracts.

Due to high natural gas prices and the potential for successes within the Barnett shale, more capital is being invested into the region. The competition for opportunities and goods and services may result in increased operating costs. However, our experience in the Antrim shale and our experienced Barnett shale personnel provide an advantage in addressing potential cost increases. We expect to invest a combined amount of approximately $100 million to $130 million in our unconventional gas business in 2006.

Fuel Transportation and Marketing

Pipelines, Processing and Storage is in the process of expanding our storage capacity in Michigan and expanding and building new pipeline capacity to the northeast United States. Our Coal Transportation and Marketing business will seek to build our capacity to transport greater amounts of western coal and may seek to expand into coal terminals.

Significant portions of the electric and gas marketing and trading portfolio are economically hedged. The portfolio includes financial instruments and gas inventory, as well as owned and contracted natural gas pipelines and storage capacity positions. Most financial instruments are deemed derivatives, whereas the gas inventory, pipelines and storage assets are not derivatives. As a result, this segment may experience dramatic earnings volatility as derivatives are marked to market without revaluing the underlying non-derivative contracts and assets. This results in gains and losses that are recognized in different accounting periods. We incur gains or losses in one period that are subsequently reversed when transactions are settled.

During 2005, our earnings were negatively impacted by the economically favorable decision in early 2005 to delay previously planned withdrawals from gas storage due to a decrease in the current price for natural gas and an increase in the forward price for natural gas. The financial impact of this timing difference has begun to reverse as the gas is withdrawn from storage in the current storage cycle and is sold at prices significantly in excess of the cost of gas in storage. In addition, we entered into forward power contracts to economically hedge certain physical and capacity power contracts. Some of these underlying contracts are not derivatives, while the related economic hedges are derivatives, and therefore marked to market. As a result, these transactions produce the timing related earnings swings from period to period. We expect the timing difference on the forward power contracts will not be fully realized until 2007.

OPERATING SYSTEM AND PERFORMANCE EXCELLENCE PROCESS

We continuously review and adjust our cost structure and seek improvements in our processes. Beginning in 2002, we adopted the DTE Energy Operating System, which is the application of tools and operating practices that have resulted in operating efficiencies, inventory reductions and improvements in technology systems, among other enhancements. Some of these cost reductions may be returned to our customers in the form of lower PSCR charges and the remaining amounts may impact our profitability.

As an extension of this effort, in mid-2005, we initiated a company-wide review of our operations called the Performance Excellence Process. The overarching goal has been and remains to become more competitive by reducing costs, eliminating waste and optimizing business processes while improving customer service. Many of our customers are under intense economic pressure and will benefit from our efforts to keep down our costs and their rates. Additionally, we will need significant resources in the future to invest in the infrastructure necessary to compete. Specifically, we began a series of focused improvement initiatives within our Electric and Gas Utilities, and our corporate support function.

The process will be rigorous and challenging and seeks to yield sustainable performance to our customers and shareholders. We have identified the Performance Excellence Process as critical to our long-term growth strategy. We are entering the implementation phase and expect to begin to realize the benefits from the effort in 2006. The cost to execute the Performance Excellence Process could result in non-recurring restructuring charges in 2006.

CAPITAL INVESTMENT

We anticipate significant capital investment across all of our business segments. Most of our capital expenditures will be concentrated within our utility segments. Our electric utility currently expects to invest approximately $4 billion due to increased environmental requirements and reliability enhancement projects through 2010. Our gas utility currently expects to invest approximately $900 million on system expansion, pipeline safety and reliability enhancement projects through the same period. We plan to seek regulatory approval to include these capital expenditures within our regulatory rate base.

During 2005, we began the first wave of implementation of DTE2, an enterprise resource planning system initiative to improve existing processes and to implement new core information systems. We anticipate spending $165 million to $190 million over the next two years as the remaining system elements are developed and business segments fully adopt DTE2.

In the future, we may build a new base-load electric generating plant. The last base load plant constructed within our electric utility service territory was approximately twenty years ago. A recently completed study, sponsored by the MPSC, projected that Michigan may need to install 7,000 MW of additional capacity over the next ten years. We estimate that a new base-load plant will cost between $1 billion and $2 billion.

OUTLOOK

The next few years will be a time of rapid change for DTE Energy and for the energy industry. Our strong utility base combined with our integrated non-utility operations position us well for long-term growth. Due to the enactment of the Energy Policy Act of 2005 and the repeal of the Public Utility Holding Company Act of 1935 there are fewer barriers to mergers and acquisitions of utility companies. We anticipate greater industry consolidation over the next few years resulting in the creation of large regional utility providers.

Looking forward, we will focus on several points that we expect will improve future performance:

- continuing to pursue regulatory stability and investment recovery for our utilities;
- managing the growth of our utility asset base;
- enhancing our cost structure across all business segments;
- improving our Electric and Gas Utility customer satisfaction;
- increasing the scale in our three non-utility business segments; and
- investing in businesses that integrate our assets and leverage our skills and expertise.

Along with pursuing a leaner organization, we expect to receive an estimated $1.2 billion (assuming no phase-out) of synfuel cash flow through 2008, which consists of cash from operations, asset sales, and the utilization of production tax credits to reduce tax payments. Tax credit utilization in part could be extended past 2008, if taxable income is reduced from current forecasts. However, if oil prices remain at current levels or continue to increase, the estimated cash flow from the synfuel business would, as a result of production tax credit phase-out, be significantly less and would adversely impact the success of this strategy, unless we identify alternative sources of cash.

Anticipated redeployment of this expected available cash will reduce DTE Energy's debt and replace the value of synfuel operations inherent in our share price by pursuing investments in targeted energy markets. If adequate investment opportunities are not available, share repurchases may be used to build shareholder value. We remain committed to a strong balance sheet and financial coverage ratios, and paying an attractive dividend.

RESULTS OF OPERATIONS

Net income in 2005 was $537 million, or $3.05 per diluted share, compared to net income of $431 million, or $2.49 per diluted share in 2004 and net income of $521 million, or $3.09 per diluted share in 2003. The comparability of earnings was impacted by our discontinued businesses, DTE Energy Technologies (Dtech), Southern Missouri Gas Company and ITC, and the adoption of a new accounting rule in 2005 and two new accounting rules in 2003. Excluding discontinued operations and the cumulative effect of accounting changes, our income from continuing operations in 2005 was $576 million, or $3.27 per diluted share, compared to income of $461 million, or $2.66 per diluted share in 2004 and income of $494 million, or $2.93 per diluted share in 2003. The following sections provide a detailed discussion of our segments, operating performance and future outlook.

(in Millions, except per share data)	2005	2004	2003
Net Income (Loss)			
Electric Utility	**$ 277**	$ 150	$ 252
Gas Utility	**37**	20	29
Non-utility Operations:			
Power and Industrial Projects	**308**	179	197
Unconventional Gas Production	**4**	6	12
Fuel Transportation and Marketing	**2**	118	69
Corporate & Other	**(52)**	(12)	(65)
Income (Loss) from Continuing Operations:			
Utility	**314**	170	281
Non-utility	**314**	303	278
Corporate & Other	**(52)**	(12)	(65)
	576	461	494
Discontinued Operations	**(36)**	(30)	54
Cumulative Effect of Accounting Changes	**(3)**	—	(27)
Net Income	**$ 537**	$ 431	$ 521
Diluted Earnings Per Share			
Total Utility	**$ 1.78**	$ .98	$ 1.67
Non-utility Operations	**1.78**	1.75	1.65
Corporate & Other	**(.29)**	(.07)	(.39)
Income from Continuing Operations	**3.27**	2.66	2.93
Discontinued Operations	**(.20)**	(.17)	.32
Cumulative Effect of Accounting Changes	**(.02)**	—	(.16)
Net Income	**$ 3.05**	$ 2.49	$ 3.09

The earnings per share of any segment does not represent a direct legal interest in the assets and liabilities allocated to any one segment but rather represents a direct or indirect equity interest in DTE Energy's assets and liabilities as a whole.

ELECTRIC UTILITY

Our Electric Utility segment consists of Detroit Edison, which is engaged in the generation, purchase, distribution and sale of electricity to approximately 2.2 million customers in southeastern Michigan.

Factors impacting income: Our net income increased $127 million to $277 million in 2005 from $150 million in 2004. 2004 net income decreased $102 million from $252 million in 2003. These results primarily reflect higher rates due to the November 2004 MPSC final rate order, return of customers from the electric Customer Choice program, warmer weather and lower operations and maintenance expenses in 2005, partially offset by a portion of higher fuel and purchased power costs, which were unrecoverable as a result of residential rate caps (which expired January 1, 2006), and increased depreciation and amortization expenses.

(in Millions)	2005	2004	2003
Operating Revenues	**$ 4,462**	$ 3,568	$ 3,695
Fuel and Purchased Power	**1,590**	885	939
Gross Margin	**2,872**	2,683	2,756
Operation and Maintenance	**1,308**	1,395	1,332
Depreciation and Amortization	**640**	523	473
Taxes Other Than Income	**241**	249	257
Asset (Gains) and Losses, Net	**(26)**	(1)	20
Operating Income	**709**	517	674
Other (Income) and Deductions	**283**	303	277
Income Tax Provision	**149**	64	145
Net Income	**$ 277**	$ 150	$ 252
Operating Income as a Percent of Operating Revenues	**16%**	14%	18%

Gross margins increased $189 million during 2005 and declined $73 million in 2004. Operating revenues increased due to higher demand resulting from warmer weather in 2005 and increased rates due to the November 2004 MPSC final rate order, partially offset by unrecovered power supply costs as a result of residential rate caps (which expired January 1, 2006) and a poor Michigan economy in 2005. Gross margins were favorably impacted by decreased electric Customer Choice penetration, whereby Detroit Edison lost 12% of retail sales to electric Customer Choice customers in 2005 and 18% of such sales during 2004 as retail customers migrated back to Detroit Edison as their electric generation provider rather than remaining with alternative suppliers. The following table displays changes in various gross margin components relative to the comparable prior period:

Increase (Decrease) in Gross Margin Components Compared to Prior Year (in Millions)	**2005**	2004
Weather related margin	**$ 166**	$ (25)
MPSC 2004 rate orders	**116**	22
Unrecovered power supply costs – residential customers	**(73)**	—
Transmission charges (1)	**(93)**	—
Electric Customer Choice program	**79**	(82)
Service territory economic performance	**(23)**	9
Other, net	**17**	3
Increase (decrease) in gross margin	**$ 189**	$ (73)

(1) Transmission expenses were recorded in operation and maintenance expense in 2004.

Operating revenues and fuel and purchased power costs increased in 2005 reflecting a $8.79 per MWh (58%) increase in fuel and purchased power costs during the year. Fuel and purchased power costs are a pass-through with the reinstatement of the PSCR mechanism, except for residential customers whose rate caps expired in January 2006.

The increase in power supply costs was driven by higher seasonal demand, higher purchased power rates, higher coal prices and increased power purchases due to weather and plant outages. Pursuant to the MPSC final rate order, transmission expense, previously recorded in operation and maintenance expenses in 2004, is now reflected in purchased power expenses. The PSCR mechanism provides related revenues for the transmission expense.

The decline in 2004 revenues was partially offset by increased base rates resulting from the interim and final rate orders. Revenues in 2004 were adversely impacted by reduced cooling demand resulting from mild summer weather. In addition, operating revenues and fuel and purchased power costs decreased in 2004 reflecting a $1.27 per MWh (8%) decline in fuel and purchased power costs. The loss of retail sales under the electric Customer Choice program also resulted in lower purchase power requirements, as well as excess power capacity that was sold in the wholesale market. Under the 2004 interim and final rate orders, revenues from selling excess power reduce the level of recoverable fuel and purchased power costs and, therefore, do not impact margins associated with uncapped customers.

The rate orders also lowered PSCR revenues, which were partially offset by increased base rate and transition charge revenues. Since fuel and purchased power costs are a pass-through with the reinstatement of the PSCR in 2004, a decrease affects both revenues and fuel and purchased power costs but does not affect margins or earnings associated with uncapped customers. The decrease in fuel and purchased power costs is attributable to lower priced purchases and the use of a more favorable power supply mix driven by higher generation output. The favorable mix is due to lower purchases, driven by lost sales under the electric Customer Choice program.

Power Generated and Purchased (in Thousands of MWh)	2005		2004		2003	
Power Plant Generation						
Fossil	**40,756**	**73%**	39,432	75%	38,052	72%
Nuclear	**8,754**	**16**	8,440	16	8,114	16
	49,510	**89**	47,872	91	46,166	88
Purchased Power	**6,378**	**11**	4,650	9	6,354	12
System Output	**55,888**	**100%**	52,522	100%	52,520	100%
Less Line Loss and Internal Use	**(3,205)**		(3,574)		(3,248)	
Net System Output	**52,683**		48,948		49,272	
Average Unit Cost ($/MWh)						
Generation (1)	**$ 15.47**		$ 12.98		$ 12.89	
Purchased Power	**$ 89.37**		$ 37.06		$ 41.73	
Overall Average Unit Cost	**$ 23.90**		$ 15.11		$ 16.38	

(1) Represents fuel costs associated with power plants.

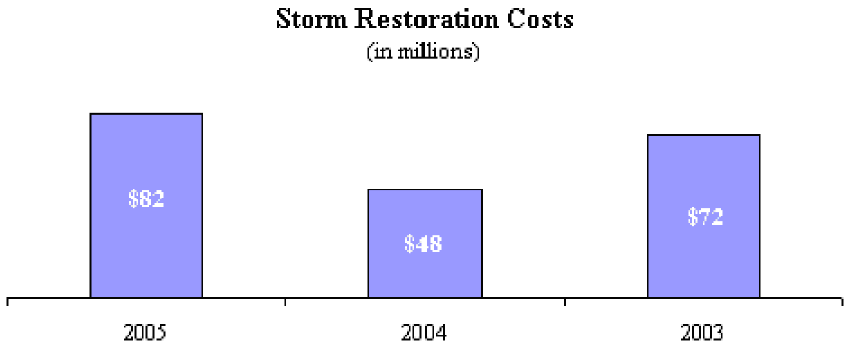
(in Thousands of MWh)	2005	2004	2003
Electric Sales			
Residential	**16,812**	15,081	15,074
Commercial	**15,618**	13,425	15,942
Industrial	**12,317**	11,472	12,254
Wholesale	**2,329**	2,197	2,241
Other	**390**	401	402
	47,466	42,576	45,913
Interconnection sales (1)	**5,217**	6,372	3,359
Total Electric Sales	**52,683**	48,948	49,272
Electric Deliveries			
Retail and Wholesale	**47,466**	42,576	45,913
Electric Choice	**6,760**	9,245	6,193
Electric Choice – Self Generators (2)	**518**	595	1,088
Total Electric Sales and Deliveries	**54,744**	52,416	53,194

(1) Represents power that is not distributed by Detroit Edison.

(2) Represents deliveries for self generators who have purchased power from alternative energy suppliers to supplement their power requirements.

Operation and maintenance expense decreased $87 million in 2005 and increased $63 million in 2004. As a result of the MPSC final rate order, transmission and MISO expenses in 2005 are now included in purchased power expense with related revenues recorded through the PSCR mechanism. In addition, as a result of the MPSC final rate order, merger interest is no longer allocated from the DTE Energy parent company to Detroit Edison. Partially offsetting the lack of merger interest expense and the transmission expense accounting reclassification were higher 2005 storm expenses.

The 2004 increase reflects costs associated with maintaining our generation fleet, including costs of scheduled and forced plant outages. Additionally, the increase in 2004 is due to incremental costs associated with the implementation of our DTE2 project.



Operation and maintenance expense in both years includes higher employee pension and health care benefit costs due to financial market performance, discount rates and health care cost trend rates, and increased reserves for uncollectible accounts receivable, reflecting high past-due amounts attributable to economic conditions. In addition, we accrued a refund due from the Midwest Independent System Operator in 2004 for transmission services.

Depreciation and amortization expense increased $117 million in 2005 and increased $50 million in 2004. The increases reflect the income effect of recording regulatory assets, which lowered depreciation and amortization expenses. The regulatory asset deferrals totaled $46 million in 2005, $107 million in 2004 and $153 million in 2003, representing net stranded costs and other costs we believe are recoverable under Public Act (PA) 141. Additionally, higher 2005 sales volumes compared to 2004 resulted in greater amortization of regulatory assets.

Asset (gains) and losses, net increased $25 million in 2005 as a result of our sale of land near our headquarters.

Other income and deductions expense decreased $20 million in 2005 and increased $26 million in 2004. The 2005 decrease is due primarily to lower interest expense as a result of lower interest rates and a favorable adjustment related to tax audit settlements. The 2004 increase is primarily due to lower income associated with recording a return on regulatory assets, as well as costs associated with addressing the structural issues of PA 141.

Outlook – We continue to improve the operating performance of Detroit Edison. During the past year we have resolved many of our regulatory issues and continue to pursue additional regulatory solutions for structural problems within our competitive environment, mainly electric Customer Choice and the need to adjust rates for each customer class to reflect the full cost of service.

Concurrently, we will move forward in our efforts to improve performance. Looking forward, additional issues, such as rising prices for coal, uranium and health care, continued under-performance of Michigan's economy and capital spending, will result in us taking meaningful action to address our costs while continuing to provide quality customer service. We will utilize the DTE Operating System and the Performance Excellence Process to seek opportunities to improve productivity, remove waste, decrease our costs, while improving customer satisfaction.

Long term, we will be required to invest an estimated $2.4 billion on emission controls through 2018. Should we be able to recover these costs in future rate cases, we may experience a growth in earnings. Additionally, our service territory may require additional generation capacity. A new base-load generating plant has not been built within the State of Michigan in the last 20 years. Should our regulatory environment be conducive to such a significant capital expenditure, we may build or expand a new base- load facility, with an estimated cost of $1 billion to $2 billion.

The following variables, either in combination or acting alone, will impact our future results:

- amount and timing of cost recovery allowed as a result of regulatory proceedings, related appeals, or new legislation;
- our ability to reduce costs;
- variations in market prices of power, coal and gas;
- plant performance;
- economic conditions within the state of Michigan;
- weather, including the severity and frequency of storms; and
- levels of customer participation in the electric Customer Choice program.

We expect cash flows and operating performance will continue to be at risk due to the electric Customer Choice program until the issues associated with this program are adequately addressed. We will accrue as regulatory assets any future unrecovered generation-related fixed costs (stranded costs) due to electric Customer Choice that we believe are recoverable under Michigan legislation and MPSC orders. We cannot predict the outcome of these matters. See Note 4.

GAS UTILITY

Our Gas Utility segment consists of MichCon and Citizens Fuel Gas Company (Citizens), natural gas utilities subject to regulation by the MPSC. MichCon is engaged in the purchase, storage, transmission, distribution and sale of natural gas to approximately 1.3 million residential, commercial and industrial customers in the State of Michigan. MichCon also has subsidiaries involved in the gathering and transmission of natural gas in northern Michigan. MichCon operates one of the largest natural gas distribution and transmission systems in the United States. Citizens distributes natural gas in Adrian, Michigan.

Factors impacting income: Gas Utility's net income increased $17 million in 2005 and declined $9 million in 2004, compared to the prior year, primarily reflecting the impact of the MPSC's April 2005 gas cost recovery and final rate orders.

The MPSC final gas rate order disallowed recovery of 90% of the costs of a computer billing system that was in place prior to DTE Energy's acquisition of MCN Energy in 2001. MichCon impaired this asset by approximately $42 million in the first quarter of 2005. This disallowance was not reflected at the DTE Energy level since this impairment was previously reserved at the time of the MCN acquisition in 2001.

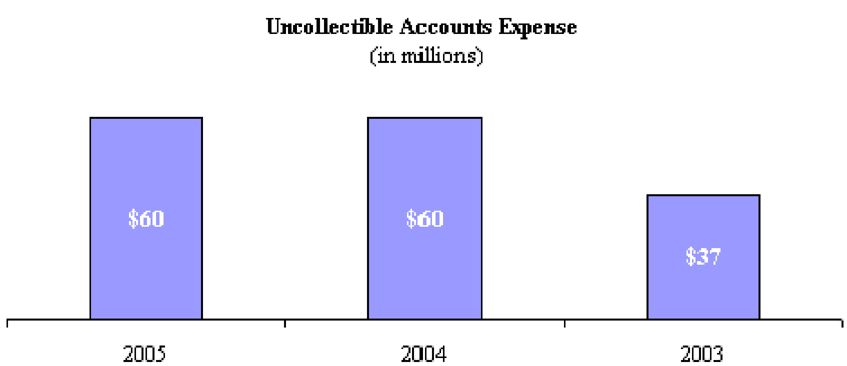
(in Millions)	**2005**	2004	2003
Operating Revenues	**$ 2,138**	$ 1,682	$ 1,498
Cost of Gas	**1,490**	1,071	909
Gross Margins	**648**	611	589
Operation and Maintenance	**424**	403	371
Depreciation and Amortization	**95**	103	101
Taxes Other Than Income	**43**	49	52
Asset (Gains) and Losses, Net	**4**	(3)	—
Operating Income	**82**	59	65
Other (Income) and Deductions	**47**	48	36
Income Tax Benefit	**(2)**	(9)	—
Net Income	**$ 37**	$ 20	$ 29
Operating Income as a Percent of Operating Revenues	**4%**	4%	4%

Gross margins increased $37 million in 2005 and increased $22 million in 2004, compared to the prior year. Gross margins in 2005 were favorably affected by higher base rates as a result of the interim and final gas rate orders, and revenue associated with the uncollectible expense tracking mechanism authorized by the MPSC. In April 2005, the MPSC issued an order in the 2002 GCR reconciliation case that disallowed $26 million representing unbilled revenues at December 2001. We recorded the impact of the disallowance during the first quarter of 2005. Operating revenues and cost of gas increased in 2005 reflecting higher gas prices which are recoverable from customers through the GCR mechanism. The 2004 gross margin comparison was also affected by a $26.5 million pre-tax reserve recorded in 2003 for the potential disallowance in gas costs pursuant to an MPSC order in MichCon's 2002 GCR plan case. See Note 4.

	2005	2004	2003
Gas Markets (in Millions)			
Gas sales	**$ 1,860**	$ 1,435	$ 1,242
End user transportation	**134**	119	136
	1,994	1,554	1,378
Intermediate transportation	**58**	56	51
Other	**86**	72	69
	$ 2,138	$ 1,682	$ 1,498
Gas Markets (in Bcf)			
Gas sales	**168**	173	181
End user transportation	**157**	145	152
	325	318	333
Intermediate transportation	**432**	536	576
	757	854	909

Operation and maintenance expense increased $21 million in 2005 and $32 million in 2004. The 2005 increase is primarily due to the impact of the MPSC rate order that disallowed certain environmental expenses that had been recorded as a regulatory asset and its requirement to defer negative pension expense as a regulatory liability. For 2005, uncollectible accounts receivables expense remained consistent with 2004, reflecting higher past due amounts attributable to an increase in gas prices, continued weak economic conditions and inadequate government-sponsored assistance for low-income customers. The 2005 final rate order provided revenue for an uncollectible expense tracking mechanism to mitigate some of the effect of increasing uncollectible expense. The increase in operation and maintenance expense was partially offset by the DTE Energy parent company no longer allocating merger-related interest to MichCon effective in April 2005, as a result of the disallowance of those costs in the April 2005 final rate order. The increase was also partially offset by a decline in accruals for injuries and damages during 2005.

The 2004 period reflects higher reserves for uncollectible accounts receivable and pension and health care costs. The increase in uncollectible accounts expense reflects high past due amounts attributable to an increase in gas prices, continued weak economic conditions and a lack of adequate public assistance for low-income customers.



Asset (gains) and losses, net declined $7 million in 2005 as a result of a write-off of certain computer equipment and related depreciation resulting from the April 2005 final rate order.

Income taxes increased by $7 million in 2005 and decreased by $9 million in 2004 due to variations in pre-tax earnings.

Outlook – Operating results are expected to vary as a result of factors such as regulatory proceedings, weather, changes in economic conditions, cost containment efforts and process improvements. Higher gas prices and economic conditions have resulted in continued pressure on receivables and working capital requirements partially mitigated by the GCR mechanism. We believe our allowance for doubtful accounts is based on reasonable estimates. In the April 2005 final gas rate order, the MPSC adopted MichCon's proposed tracking mechanism for uncollectible accounts receivable. Each year, MichCon will file an application comparing its actual uncollectible expense for the prior calendar year to its designated revenue recovery of approximately $37 million. Ninety percent of the difference will be refunded or surcharged after an annual reconciliation proceeding before the MPSC.

NON-UTILITY OPERATIONS

Power and Industrial Projects

Power and Industrial Projects is comprised of Coal-Based Fuels, On-Site Energy Projects, Non-Utility Power Generation, Landfill Gas Recovery and Waste Coal Recovery. Coal-Based Fuels operations include producing synthetic fuel from nine synfuel plants and producing coke from two coke battery plants. The production of synthetic fuel from all of our synfuel plants and the production of coke from one of our coke batteries generate production tax credits. On-Site Energy Projects include pulverized coal injection, power generation, steam production, chilled water production, wastewater treatment and compressed air supply. Non-Utility Power Generation owns and operates four gas-fired peaking electric generating plants and manages and operates one additional gas-fired power plant under contract. Landfill Gas Recovery develops, owns and operates landfill recovery systems throughout the United States. Waste Coal Recovery uses proprietary technology to produce high quality coal products from fine coal slurries typically discarded from coal mining operations.

Factors impacting income: Net income increased $129 million in 2005 and decreased $18 million in 2004, compared to 2003. These results primarily reflect higher gains recognized from selling interests in our synfuel plants, gains and losses on synfuel hedges, and varying levels of production tax credits.

(in Millions)	**2005**	2004	2003
Operating Revenues	**$ 1,356**	$ 1,100	$ 938
Operation and Maintenance	**1,497**	1,216	1,108
Depreciation and Amortization	**107**	89	90
Taxes other than Income	**34**	16	18
Asset (Gains) and Losses, Net	**(368)**	(215)	(114)
Operating Income (Loss)	**86**	(6)	(164)
Other (Income) and Deductions	**(30)**	(15)	1
Minority Interest	**(281)**	(212)	(91)
Income Taxes			
Provision (Benefit)	**144**	80	(30)
Production Tax Credits	**(55)**	(38)	(241)
	89	42	(271)
Net Income	**$ 308**	$ 179	$ 197

Operating revenues increased $256 million in 2005 and $162 million in 2004 primarily reflecting higher synfuel sales due to increased production, and higher market prices for our coke production. Operating expenses associated with synfuel projects exceed operating revenues and therefore generate operating losses, which have been more than offset by the resulting production tax credits. When we sell an interest in a synfuel project, we recognize the gain from such sale as the facility produces and sells synfuel and when there is persuasive evidence that the sales proceeds have become fixed or determinable and collectibility is reasonably assured.

The improvement in 2004 synfuel revenues results from increased production due to additional sales of project interests in 2004, reflecting our strategy to produce synfuel primarily from plants in which we had sold interests in order to optimize income and cash flow.

Revenues from on-site energy projects increased in 2005, reflecting the addition of new facilities, completion of new long-term utility services contracts with a large automotive company and a large manufacturer of paper products. Revenues in 2004 include a $9 million pre-tax fee generated in conjunction with the development of a related energy project, 50% of which was sold to an unaffiliated partner.

Operation and maintenance expense increased $281 million in 2005 and $108 million in 2004, reflecting costs associated with increased synfuel production, 2005 acquisitions of three on-site energy projects and coke operations. Partially offsetting 2004 higher synfuel operating costs was the recording of insurance proceeds associated with an accident at one of our coke batteries.

Asset (gains) and losses, net increased $153 million in 2005 and $101 million in 2004. The improvements are due to increased production and sales volume from our synfuel projects. To economically hedge our exposure to the risk of an increase in oil prices that could reduce synfuel sales proceeds, we entered into derivative and other contracts. The derivative contracts are marked to market with changes in their fair value recorded as an adjustment to synfuel gains. We recorded 2005 synfuel hedge mark to market gains of $48 million, compared to 2004 mark to market losses of $12 million. See Note 12.

Minority interest increased $69 million in 2005 and $121 million in 2004, reflecting our partners' share of operating losses associated with synfuel operations. The sale of interests in our synfuel facilities during prior periods resulted in allocating a larger percentage of such losses to our partners.

Income taxes increased $47 million in 2005 and $313 million in 2004. The increase in 2005 reflects higher taxable earnings, partially offset by higher production tax credits. The increase in 2004 reflects higher taxable earnings and a decline in the level of production tax credits due to the sale of interests in synfuel facilities.

Outlook - We may sell additional interests in our synfuel plants and take actions to protect our expected synfuel cash flows from the risk of an oil price-related phase-out. Synfuel-related tax credits expire on December 31, 2007.

In the third quarter of 2005, we executed an agreement to purchase five on-site energy projects and closed on three of the projects in 2005.

Power and Industrial Projects will continue leveraging its extensive energy-related operating experience and project management capability to develop and grow the on-site energy business. We expect solid earnings from our on-site energy business in 2006.

Production tax credits generated by our Coal-Based Fuels and Landfill Gas Recovery businesses are subject to the same phase out risk if domestic crude oil prices reach certain levels. See Note 13.

Unconventional Gas Production

Unconventional Gas Production is primarily engaged in natural gas exploration, development and production. Our Unconventional Gas Production business produces gas from the Antrim and Barnett shales and sells most of the gas to the Fuel Transportation and Marketing segment.

Factors impacting income: Net income decreased $2 million in 2005 and decreased $6 million in 2004. The decline in 2005 is due to higher operating and Michigan severance tax expenses. The decline in 2004 is due to increased interest costs and a gain that was recognized in 2003 as a result of a sale of a non-core asset.

(in Millions)	**2005**	2004	2003
Operating Revenues	**$ 74**	$ 71	$ 70
Operation and Maintenance	**30**	27	22
Depreciation and Amortization	**20**	18	17
Taxes Other Than Income	**11**	7	7
Operating Income	**13**	19	24
Other (Income) and Deductions	**8**	10	7
Income Tax Provision	**1**	3	5
Net Income	**$ 4**	$ 6	$ 12

Operating revenues increased $3 million in 2005 and increased $1 million in 2004 due primarily to higher gas prices.

Operations and maintenance expenses increased $3 million in 2005 and increased $5 million in 2004. Increases are associated with the addition of approximately 300 producing wells during the three year period. The 2004 increase is also due to a $6 million pretax gain on the sale of non-core assets recorded in 2003.

Taxes other than income increased $4 million in 2005 due to higher severance taxes associated with gas price increases.

Other (income) and deductions decreased $2 million in 2005 and increased $3 million in 2004. Interest expense was the primary contributor to the variances.

Outlook – We expect to continue to develop our proved areas, test unproved areas and prudently add new acreage in Michigan and Texas. During 2005 we increased our acreage holdings by 38,437 acres (24,852 net of the interest of others) in the Antrim and Barnett shales. Results from the Barnett shale test wells drilled during 2005 are expected during the first half of 2006. We expect to invest a combined amount of approximately $100 million to $130 million in our unconventional gas business in 2006.

Fuel Transportation and Marketing

Fuel Transportation and Marketing consists of DTE Energy Trading, Coal Transportation and Marketing and the Pipelines, Processing and Storage business.

DTE Energy Trading focuses on physical power and gas marketing, structured transactions, enhancement of returns from DTE Energy's power plants and the optimization of contracted natural gas pipelines and storage capacity positions. Our customer base is predominantly utilities, local distribution companies, large industrials, and other marketing and trading companies. We enter into derivative financial instruments as part of our marketing and hedging activities. Most of the derivative financial instruments are accounted for under the mark-to-market method, which results in earnings recognition of unrealized gains and losses from changes in the fair value of the derivatives. We utilize forwards, futures, swaps and option contracts to mitigate risk associated with our marketing and trading activity as well as for proprietary trading within defined risk guidelines. DTE Energy Trading is integral in providing commodity risk management services to the other unregulated businesses within DTE Energy.

Coal Transportation and Marketing provides fuel, transportation and rail equipment management services. We specialize in minimizing fuel costs and maximizing reliability of supply for energy-intensive customers. Additionally, we participate in coal trading and coal-to-power tolling transactions, as well as the purchase and sale of emissions credits. We recently initiated a new business line, coal mine methane extraction, in which we recover methane gas from mine voids for processing and delivery to natural gas pipelines, industrial users, or for small power generation projects.

Pipelines, Processing and Storage has a partnership interest in an interstate transmission pipeline, seven carbon dioxide processing facilities and a natural gas storage field, as well as lease rights to another natural gas storage field. The assets of these businesses are well integrated with other DTE Energy operations.

Factors impacting income: Net income decreased $116 million in 2005, consisting primarily of a $131 million decline at DTE Energy Trading associated with mark-to-market losses on gas storage hedges. Net income increased $49 million in 2004, consisting primarily of a $47 million improvement at DTE Energy Trading. The comparability of results is impacted by a $74 million one-time pretax gain from a contract modification/termination recorded in the first quarter of 2004 and significant 2005 mark-to-market losses on derivative contracts used to economically hedge our gas in storage and forward power contracts.

(in Millions)	**2005**	2004	2003
Operating Revenues	**$ 1,684**	$ 1,254	$ 1,061
Fuel, Purchased Power and Gas	**970**	473	643
Operation and Maintenance	**710**	596	334
Depreciation and Amortization	**7**	6	4
Taxes Other Than Income	**3**	4	2
Operating Income (Loss)	**(6)**	175	78
Other (Income) and Deductions	**(7)**	(7)	(32)
Income Tax Provision (Benefit)	**(1)**	64	41
Net Income	**$ 2**	$ 118	$ 69

Operating revenues increased $430 million in 2005 and increased $193 million in 2004. Both Coal Transportation and Marketing and DTE Energy Trading experienced revenue growth in 2005 due to higher demand, higher commodity pricing, the sale of emission credits and increased trading volume. Comparability of 2005 to 2004 is affected because our trading operations recorded an adjustment in 2004 that increased revenue by $86 million related to the modification of a future purchase commitment under a transportation agreement with an interstate pipeline company. See Note 13.

Coal Transportation and Marketing revenues in 2004 were affected by our strategy to produce synfuel primarily from plants in which we had sold interests. This strategy resulted in the reduction of synfuel production levels. We were contractually obligated to supply coal to customers at certain sites that did not produce synfuel as a result of our production strategy. To meet our obligations to provide coal under long-term contracts with customers, we acquired coal that was resold to customers. The coal was sold at prices higher than the prices at which synfuel would have been sold to these customers.

Fuel, purchased power and gas increased $497 million in 2005 and decreased $170 million in 2004. During 2005, our earnings have been negatively impacted by the economically favorable decision in early 2005 to delay previously planned withdrawals from gas storage due to a decrease in the current price for natural gas and an increase in the forward price for natural gas. We anticipate the financial impact of this timing difference will reverse when the gas is withdrawn from storage in the current storage cycle and is sold at prices significantly in excess of the cost of gas in storage. In addition, we entered into forward power contracts to economically hedge certain physical and capacity power contracts. We expect the timing difference on the forward power contracts will be fully realized by the end of 2007.

In 2004, our trading operations recorded a gas inventory adjustment that increased expense by $12 million related to the termination of a long-term gas exchange agreement with an interstate pipeline company. See Note 13. Under the gas exchange agreement, we received gas from the customer during the summer injection period and redelivered the gas during the winter heating season.

Operation and maintenance expenses increased $114 million in 2005 and increased $262 million in 2004. During 2005, our Coal Transportation and Marketing business experienced higher throughput volumes and increased prices for coal. The increase in 2004 was due primarily to increased coal purchases and increased lease expense.

Other (income) and deductions for 2005 remained consistent with 2004, and decreased $25 million in 2004. The decline in 2004 is primarily due to gains recorded in 2003 from selling our 16% pipeline interest in the Portland Natural Gas Transmission System.

Income tax provision decreased $65 million in 2005 and increased $23 million in 2004 due to variations in earnings.

Outlook – We expect to continue to grow our Coal Services and DTE Energy Trading businesses in a manner consistent with, and complementary to, the growth of our other business segments. Gas storage and transportation capacity enhances our ability to provide reliable and custom-tailored bundled services to large-volume end users and utilities. This capacity, coupled with the synergies from DTE Energy’s other businesses, positions the segment to add value and mitigate risks.

We expect to continue to grow our Pipeline, Processing and Storage business by expanding existing assets and developing new assets. Pipelines, Processing and Storage received MPSC approval in September 2005 and executed long-term contracts for a capacity expansion at one of our Michigan storage fields that will facilitate an additional 14 Bcf of storage service sales starting in April 2006. Vector Pipeline has secured long-term market commitments to support an expansion project, for approximately 200 MMcf per day, with a projected in-service date of November 2007. Vector Pipeline expects to receive FERC approval in the second quarter of 2006. The Millennium Pipeline filed an application for FERC approval in August 2005. In addition, Pipeline, Processing and Storage owns a 10.5% interest in the Millennium Pipeline and is currently negotiating to increase its equity interest.

Significant portions of the Fuel Transportation and Marketing portfolio are economically hedged. The portfolio includes financial instruments and gas inventory, as well as capacity positions of natural gas storage and pipelines and power transmission contracts. The financial instruments are deemed derivatives, whereas the gas inventory, pipelines and storage assets are not derivatives. As a result, we will experience earnings volatility as derivatives are marked to market without revaluing the underlying non-derivative contracts and assets. The majority of such earnings volatility is associated with the natural gas storage cycle, which does not coincide with the calendar and fiscal year, but runs annually from April of one year to March of the next year. Our strategy is to economically hedge the price risk of storage with over-the-counter forwards and futures. Current accounting rules require the marking to market of forward sales and futures, but do not allow for the marking to market of the related gas inventory. This results in gains and losses that are recognized in different interim and annual accounting periods. We generally anticipate the financial impact of this timing difference will reverse by the end of each storage cycle. See “Fair Value of Contracts” section that follows.

CORPORATE & OTHER

Corporate & Other includes various corporate support functions such as accounting, legal and information technology services. As these functions essentially support the entire Company, their costs are fully allocated to the various segments based on services utilized. Therefore the effect of the allocation on each segment can vary from year to year. Additionally, Corporate & Other holds certain non-utility debt, assets held for sale, and energy related investments.

Factors impacting income: Corporate & Other results declined $40 million in 2005, compared to a $53 million improvement in 2004. The 2005 decline was primarily a result of the parent company not allocating merger interest to Detroit Edison and MichCon. Partially offsetting 2005 increased expenses were reduced Michigan Single Business Taxes and gains on the sale of non-strategic assets. The 2004 improvement was affected by a $14 million net of tax gain from the sale of 3.5 million shares of Plug Power stock, as well as lower Michigan Single Business Taxes, resulting from tax saving initiatives. Corporate & Other also benefited from lower financing costs.

DISCONTINUED OPERATIONS

DTE Energy Technologies (Dtech) - We own Dtech, which assembles, markets, distributes and services distributed generation products, provides application engineering, and monitors and manages on-site generation system operations. In July 2005, management approved the restructuring of this business resulting in the identification of certain assets and liabilities to be sold or abandoned, primarily associated with standby and continuous duty operations. We recognized a net of tax restructuring loss of $23 million during the third quarter of 2005 primarily representing the write down to fair value of the assets of Dtech, less costs to sell, and the write-off of goodwill. As we execute the restructuring plan, there may be adjustments to amounts recorded related to the impairment and exit costs. We anticipate completing the restructuring plan by mid-2006.

Southern Missouri Gas Company - We owned Southern Missouri Gas Company (SMGC), a public utility engaged in the distribution, transmission and sale of natural gas in southern Missouri. In the first quarter of 2004, management approved the marketing of SMGC for sale. As of March 31, 2004, SMGC met the criteria of an asset “held for sale” and we have reported its operating results as a discontinued operation. We recognized a net of tax impairment loss of approximately $7 million, representing the write-down to fair value of the assets of SMGC, less costs to sell, and the write-off of allocated goodwill. In November 2004, we entered into a definitive agreement providing for the sale of SMGC. Regulatory approval was received in April 2005 and the sale closed in May 2005. During the second quarter of 2005, we recognized a net of tax gain of $2 million.

International Transmission Company - In February 2003, we sold International Transmission Company (ITC), our electric transmission business, to affiliates of Kohlberg Kravis Roberts & Co. and Trimaran Capital Partners, LLC. Through December 31, 2004, we recorded a gain of $58 million (net of tax). During the second quarter of 2005, the gain was adjusted to $56 million (net of tax).

See Note 3.

CUMULATIVE EFFECT OF ACCOUNTING CHANGES

In the fourth quarter of 2005, we adopted additional new accounting rules for asset retirement obligations. The cumulative effect of adopting these new accounting rules reduced 2005 earnings by $3 million.

On January 1, 2003, we adopted new accounting rules for asset retirement obligations and energy trading activities. The cumulative effect of adopting these new accounting rules reduced 2003 earnings by $27 million.

See Note 2.

CAPITAL RESOURCES AND LIQUIDITY

DTE Energy and its subsidiaries require cash to operate and is provided by both internally and externally generated sources. We manage our liquidity and capital resources to maintain financial flexibility to meet our current and future cash flow needs.

Cash Requirements

We use cash to maintain and expand our electric and gas utilities and to grow our non-utility businesses, retire and pay interest on long-term debt and pay dividends. Our strategic direction anticipates base level capital investments and expenditures for existing businesses in 2006 of up to $1.2 billion. The capital needs of our utilities will increase due primarily to environmental related expenditures. We may spend an additional $200 million to $400 million on growth-related projects within our non-regulated businesses in 2006.

Capital spending for general corporate purposes will increase in 2006, primarily as a result of DTE2 and environmental spending. During 2005, we began the first wave of implementation of DTE2, an enterprise resource planning system initiative to improve existing processes and to implement new core information systems. We anticipate spending $165 million to $190 million over the next two years as the remaining system elements are developed and business segments fully adopt DTE2.

We anticipate environmental capital expenditures of approximately $250 million in 2006 and up to approximately $2.3 billion of future capital expenditures to satisfy both existing and proposed new requirements.

We expect non-utility capital spending will approximate $200 million to $400 million annually for the next several years. Capital spending for growth of existing or new businesses will depend on the existence of opportunities that meet our strict risk-return and value creation criteria.

Debt maturing in 2006 totals approximately $682 million.

We believe that we will have sufficient internal and external capital resources to fund anticipated capital requirements.

(in Millions)	2005	2004	2003
Cash and Cash Equivalents			
Cash Flow From (Used For)			
Operating activities:			
Net income	**$ 537**	$ 431	$ 521
Depreciation, depletion and amortization	**872**	744	691
Deferred income taxes	**147**	129	(220)
Gain on sale of ITC, synfuel and other assets, net	**(405)**	(236)	(228)
Working capital and other	**(150)**	(73)	186
	1,001	995	950
Investing activities:			
Plant and equipment expenditures – utility	**(850)**	(815)	(679)
Plant and equipment expenditures – non-utility	**(215)**	(89)	(72)
Business acquisitions, net of cash acquired	**(50)**	—	—
Proceeds from sale of ITC, synfuels and other assets, net of cash divested	**409**	325	758
Restricted cash and other investments	**(96)**	(102)	3
	(802)	(681)	10
Financing activities:			
Issuance of long-term debt and common stock	**1,041**	777	571
Redemption of long-term debt	**(1,266)**	(759)	(1,208)
Short-term borrowings, net	**437**	33	(44)
Repurchase of common stock	**(13)**	—	—
Dividends on common stock and other	**(366)**	(363)	(358)
	(167)	(312)	(1,039)
Net Increase (Decrease) in Cash and Cash Equivalents	**$ 32**	$ 2	$ (79)

Cash from Operating Activities

A majority of the Company's operating cash flow is provided by our two utilities, which are significantly influenced by factors such as weather, electric Customer Choice, regulatory deferrals, regulatory outcomes, economic conditions and operating costs.

Our non-utility businesses also provide sources of cash flow to the enterprise and reflect a range of operating profiles. The profiles vary from our synthetic fuels business, which we believe will provide approximately $1.2 billion of cash during 2006-2008 (assuming no phase-out), to new startups. These new start-ups include our unconventional gas and waste coal recovery businesses, which we are growing and, if successful, could require significant investment.

Cash from operations totaling $1.001 billion in 2005 was up $6 million from the comparable 2004 period. The operating cash flow comparison reflects an increase of over $83 million in net income, after adjusting for non-cash items (depreciation, depletion, amortization, deferred taxes and gains), substantially offset by a $77 million increase in working capital and other requirements. Most of the improvement was driven by higher net income at Detroit Edison which was the result of improved revenues and gross margin stemming from higher rates granted in the 2004 rate orders, warmer weather, and lower customer choice penetration. The offsetting increase in working capital requirements was driven by a $127 million PSCR under-recovery in 2005 as compared to a $112 million over-recovery in 2004. Working capital requirements also reflect the higher cost of gas at MichCon and our Fuel Transportation and Marketing segment. MichCon's working capital and other requirements were $136 million higher in 2005 compared to 2004 primarily due to the impact of higher gas costs. This impact was reflected by accounts receivable balances that were $198 million higher at December 31, 2005 than the previous year at MichCon. The increase in working capital requirements was mitigated by lower income tax payments in 2005 and company initiatives to improve cash flow, including better inventory management, cash sales transactions and the utilization of letters of credit.

Our net operating cash flow in 2004 was $995 million, reflecting a $45 million increase from 2003. The operating cash flow comparison reflects an increase of over $300 million in net income, after adjusting for non-cash items (depreciation, depletion, amortization, deferred taxes and gains), substantially offset by a $259 million increase in working capital and other requirements. A portion of this improvement is attributable to the change in our strategy to primarily produce synfuel from plants in which we have sold interests. As previously discussed, synfuel projects generate operating losses, which have been more than offset by tax credits that we have been unable to fully utilize, thereby negatively affecting operating cash flow. Cash for working capital primarily reflects higher income tax payments of $172 million in 2004, reflecting a different payment pattern of taxes in 2004 compared to 2003. The increase in working capital was mitigated by Company initiatives to improve cash flow, including better inventory management, cash sales transactions, deferral of retirement plan contributions and the utilization of letters of credit. Certain cash initiatives in 2003 lowered cash flow in 2004.

Outlook – We expect cash flow from operations to increase over the long-term primarily due to improvements from utility rate increases and the sales of interests in our synfuel projects, partially offset by higher cash requirements on environmental and other utility capital as well as growth investments in our non-utility portfolio. We are likely to incur costs associated with implementation of our Performance Excellence Process, but we expect to realize long term cost savings. We also may be impacted by the delayed collection of underrecoveries of our PSCR and GCR costs and electric and gas accounts receivable as a result of recent MPSC orders. Gas prices are likely to be a source of volatility with regard to working capital requirements for the foreseeable future. We are continuing our efforts to identify opportunities to improve cash flow through working capital improvement initiatives.

Operating cash flow from our utilities is expected to increase in 2006. Due to the structure of the interim and final rate orders, we will begin to realize the full benefits of interim and final rate relief in 2006 when all customer rate caps expire. Improvements in cash flow from our utilities are also expected from better management of our working capital requirements, including the continued focus on reducing past due accounts receivable. Our emphasis in these businesses will continue to be cash generation and conservation.

Assuming no production tax credit phase-out, cash flows from our synfuel business are expected to be approximately $400 million, $500 million and $300 million in 2006, 2007 and 2008, respectively, including $300 million tax credit carryforward utilization by DTE Energy. The redeployment of this cash represents a unique opportunity to increase shareholder value and strengthen our balance sheet. We expect to use this cash to reduce debt, to continue to pursue growth investments that meet our strict risk-return and value creation criteria and to potentially repurchase common stock if adequate investment opportunities are not available. Our objectives for cash redeployment are to strengthen the balance sheet and coverage ratios to improve our current credit rating and outlook, and to replace the value of synfuel operations currently inherent in our share price. However, if oil prices remain at current levels or increase throughout 2006, the expected cash flow from the synfuel business would be less and could adversely impact the success of this strategy, unless the Company identifies alternative sources of cash. Synfuel cash flow consists of variable and fixed payments from partners, proceeds from option and other contracts used to protect us from risk of loss from a tax credit phase-out and the use of prior years' tax credit carry-forwards. Since 2004, we have spent approximately $105 million hedging our future synfuel cash flow and may spend up to $50 million in 2006.

Our other operating non-utility businesses are expected to contribute approximately $500 million through 2008. Remaining start-up businesses such as unconventional gas production, waste coal recovery and distributed generation will continue to use cash in excess of their cash generation over the next couple of years while they are being further developed. Certain of the previously discussed cash initiatives resulted in accelerating the receipt of cash in 2005, which will have the impact of lowering cash flow in 2006.

Cash from Investing Activities

Cash inflows associated with investing activities are primarily generated from the sale of assets. In any given year, we will look to realize cash from under-performing or non-strategic assets. Capital spending within the utility business is primarily to maintain our generation and distribution infrastructure, comply with environmental regulations and gas pipeline replacements. Capital spending within our non-utility businesses is for ongoing maintenance and expansion. The balance of non-utility spending is for growth, which we manage very carefully. We look to make investments that meet strict criteria in terms of strategy, management skills, risks and returns. All new investments are analyzed for their rates of return and cash payback on a risk adjusted basis. We have been disciplined in how we deploy capital and will not make investments unless they meet our criteria. For new business lines, we invest tentatively based on research and analysis. We start with a limited investment, we evaluate results and either expand or exit the business based on those results. In any given year, the amount of growth capital will be determined by the underlying cash flows of the Company with a clear understanding of any potential impact on our credit ratings.

Net cash outflows relating to investing activities increased $121 million in 2005 and $691 million in 2004, compared to the prior year. The 2005 change was primarily due to increased capital expenditures, partially offset by higher synfuel proceeds. Spending on growth project investments increased $123 million in 2005 while spending on environmental projects was $44 million higher than the 2004 period. The 2004 change was primarily due to proceeds received in 2003 totaling $758 million from the sale of ITC, interests in three synfuel projects and non-strategic assets. Additionally, the change was due to variations in cash contractually designated for debt service.

Longer term, with the expected improvement at our utilities and assuming continued cash generation from the synfuel business, cash flows are expected to improve. We will continue to pursue opportunities to grow our businesses in a disciplined fashion if we can find opportunities that meet our strategic, financial and risk criteria.

Cash from Financing Activities

We rely on both short-term borrowing and long-term financing as a source of funding for our capital requirements not satisfied by the Company’s operations. Short-term borrowings, which are mostly in the form of commercial paper borrowings, provide us with the liquidity needed on a daily basis. Our commercial paper program is supported by our unsecured credit facilities.

Our strategy is to have a targeted debt portfolio blend as to fixed and variable interest rates and maturity. We continually evaluate our leverage target, which is currently 50% or lower, to ensure it is consistent with our objective to have a strong investment grade debt rating. We have completed a number of refinancings with the effect of extending the average maturity of our long-term debt and strengthening our balance sheet. The extension of the average maturity was accomplished at interest rates that lowered our debt costs.

Net cash used for financing activities improved $145 million in 2005 and improved $727 million in 2004, compared to the prior periods. The improvement in 2005 was primarily driven by the issuance of common stock which resulted from the conversion of our equity security units. The change in 2004 was primarily due to higher issuances of long-term debt and levels of short-term debt borrowings which exceeded the requirements of long-term debt redemptions.

See Note 9 – Long-Term Debt and Preferred Securities and Note 10 – Short-Term Credit Arrangements and Borrowings for more information regarding financing activities.

Amounts available under shelf registrations include $500 million at DTE Energy, $250 million at Detroit Edison and $200 million at MichCon. In 2006, we plan on filing new shelf registration statements for DTE Energy and Detroit Edison.

Common stock issuances or repurchases can also be a source or use of cash. In January 2005, we announced that the DTE Energy Board of Directors has authorized the repurchase of up to $700 million in common stock through 2008. The authorization provides Company management with flexibility to pursue share repurchases from time to time, and will depend on future cash flows and investment opportunities. No share repurchases were made in 2005. As of January 1, 2005, we discontinued issuing new DTE Energy shares for our dividend reinvestment plan, which generated approximately $50 million annually. We also contributed $170 million of DTE Energy common stock to our pension plan in the first quarter of 2004. In August 2005, we issued 3.7 million shares of common stock in conjunction with the settlement of the stock purchase component of our equity security units.

Contractual Obligations

The following table details our contractual obligations for debt redemptions, leases, purchase obligations and other long-term obligations as of December 31, 2005:

(in Millions) **Contractual Obligations**	Total	Less Than 1 Year	1-3 Years	4-5 Years	After 5 Years
Long-term debt:					
Mortgage bonds, notes and other	$ 5,821	$ 577	$ 634	$ 1,305	$ 3,305
Securitization bonds	1,400	105	363	290	642
Equity-linked securities	175	—	175	—	—
Trust preferred-linked securities	289	—	—	—	289
Capital lease obligations	124	16	43	24	41
Interest	6,035	455	1,222	673	3,685
Operating leases	536	63	128	61	284
Electric, gas, fuel, transportation and storage purchase obligations (1)	6,333	3,718	1,747	188	680
Other long-term obligations	337	153	117	21	46
Total obligations	$ 21,050	$ 5,087	$ 4,429	$ 2,562	$ 8,972

(1) Excludes amounts associated with full requirements contracts where no stated minimum purchase volume is required.

Credit Ratings

Credit ratings are intended to provide banks and capital market participants with a framework for comparing the credit quality of securities and are not a recommendation to buy, sell or hold securities. Management believes that the current credit ratings of the Company provide sufficient access to the capital markets. However, disruptions in the banking and capital markets not specifically related to the company may affect our ability to access these funding sources or cause an increase in the return required by investors.

We have issued guarantees for the benefit of various non-utility subsidiaries. In the event that our credit rating is downgraded to below investment grade, certain of these guarantees would require us to post cash or letters of credit valued at approximately $536 million at December 31, 2005. Additionally, upon a downgrade, our trading business could be required to restrict operations and our access to the short-term commercial paper market could be restricted or eliminated. While we currently do not anticipate such a downgrade, we cannot predict the outcome of current or future credit rating agency reviews. The following table shows our credit rating as determined by three nationally respected credit rating agencies. All ratings are considered investment grade and affect the value of the related securities.

Entity	Description	Credit Rating Agency: Standard & Poor's	Moody's Investors Service	Fitch Ratings
DTE Energy	Senior Unsecured Debt	BBB-	Baa2	BBB
	Commercial Paper	A-2	P-2	F2
Detroit Edison	Senior Secured Debt	BBB+	A3	A-
	Commercial Paper	A-2	P-2	F2
MichCon	Senior Secured Debt	BBB	A3	A-
	Commercial Paper	A-2	P-2	F2

CRITICAL ACCOUNTING ESTIMATES

There are estimates used in preparing the consolidated financial statements that require considerable judgment. Such estimates relate to regulation, risk management and trading activities, production tax credits, goodwill, pension and postretirement costs, the allowance for doubtful accounts, and legal and tax reserves.

Regulation

A significant portion of our business is subject to regulation. Detroit Edison and MichCon currently meet the criteria of Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation*. Application of this standard results in differences in the application of generally accepted accounting principles between regulated and non-regulated businesses. SFAS No. 71 requires the recording of regulatory assets and liabilities for certain transactions that would have been treated as revenue or expense in non-regulated businesses. Future regulatory changes or changes in the competitive environment could result in discontinuing the application of SFAS No. 71 for some or all of our businesses. If we were to discontinue the application of SFAS No. 71 on all our operations, we estimate that the extraordinary loss would be as follows:

(in Millions) Utility	
Detroit Edison (1)	$ (154)
MichCon	(43)
Total	$ (197)

(1) Excludes securitized regulatory assets

Management believes that currently available facts support the continued application of SFAS No. 71 and that all regulatory assets and liabilities are recoverable or refundable in the current rate environment. See Note 4.

Risk Management and Trading Activities

All derivatives are recorded at fair value and shown as "Assets or 1iabilities from risk management and trading activities" in the consolidated statement of financial position. Risk management activities are accounted for in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended. Through December 2002, trading activities were accounted for in accordance with Financial Accounting Standards Board (FASB) Emerging Issues Task Force (EITF) Issue No. 98-10, *Accounting for Energy Trading and Risk Management Activities*. Effective January 2003, trading activities are accounted for in accordance with SFAS No. 133. See Note 2.

The offsetting entry to "Assets or liabilities from risk management and trading activities" is to other comprehensive income or earnings depending on the use of the derivative, how it is designated and if it qualifies for hedge accounting. The fair values of derivative contracts were adjusted each reporting period for changes using market sources such as:

- published exchange traded market data
- prices from external sources
- price based on valuation models

Market quotes are more readily available for short duration contracts. Derivative contracts are only marked to market to the extent that markets are considered highly liquid where objective, transparent prices can be obtained. Unrealized gains and losses are fully reserved for transactions that do not meet this criterion.

Production Tax Credits

We generate production tax credits from our synfuel, coke battery and landfill gas recovery operations. We recognize earnings as tax credits are generated at our facilities in one of two ways. First, to the extent we have sold an interest in our synfuel facilities to third parties, we recognize gains as synfuel is produced and sold, and when there is persuasive evidence that the sales proceeds have become fixed or determinable and collectibility is reasonably assured. Second, to the extent we generate credits to our own account, we recognize earnings through reduced tax expense.

All production tax credits are subject to audit by the IRS. However, all of our synfuel facilities have received favorable private letter rulings from the IRS with respect to their operations. Audits of five of our synfuel facilities were successfully completed in the past two years. If production tax credits were disallowed in whole or in part as a result of an IRS audit, there could be a significant write-off of previously recorded earnings from such tax credits.

Tax credits generated by our facilities were $617 million in 2005, as compared to $449 million in 2004 and $387 million in 2003. The portion of tax credits generated for our own account was $55 million in 2005, as compared to $38 million in 2004 and $241 million in 2003, with the remaining credits generated allocated to third party partners.

Goodwill

Certain of our business units have goodwill resulting from purchase business combinations. In accordance with SFAS No. 142, *Goodwill and Other Intangible Assets,* each of our reporting units with goodwill is required to perform impairment tests annually or whenever events or circumstances indicate that the value of goodwill may be impaired. In order to perform these impairment tests, we must determine the reporting unit's fair value using valuation techniques, which use estimates of discounted future cash flows to be generated by the reporting unit. These cash flow valuations involve a number of estimates that require broad assumptions and significant judgment by management regarding future performance. To the extent estimated cash flows are revised downward, the reporting unit may be required to write down all or a portion of its goodwill, which would adversely impact our earnings.

As of December 31, 2005, our goodwill totaled $2.1 billion. The majority of our goodwill is allocated to our utility reporting units, with $772 million allocated to the Gas Utility reporting unit. The value of the utility reporting units may be significantly impacted by rate orders and the regulatory environment. The Gas Utility reporting unit is comprised primarily of MichCon. We have made certain assumptions for MichCon that incorporate earnings multiples used in the cash flow valuations. These assumptions may change as regulatory and market conditions change.

We also have $41 million of goodwill allocated to the Power and Industrial Projects reporting unit. The value of the Power and Industrial Projects reporting unit may be significantly impacted by any phase-out of tax credits related to our synfuel business. We have assumed there will be no phase-out of synfuel tax credits and will monitor the status of any potential phase-out and its impact on our valuation assumptions.

During 2005 we recorded an impairment of $16 million to goodwill related to discontinuing the operations of Dtech.

Based on our 2005 goodwill impairment test, we determined that the fair value of our remaining operating reporting units exceed their carrying value and no impairment existed. We will continue to monitor our estimates and assumptions regarding future cash flows. While we believe our assumptions are reasonable, actual results may differ from our projections.

Pension and Postretirement Costs

Our costs of providing pension and postretirement benefits are dependent upon a number of factors, including rates of return on plan assets, the discount rate, the rate of increase in health care costs and the amount and timing of plan sponsor contributions.

We had pension costs for qualified pension plans of $90 million in 2005, $81 million in 2004, and $47 million in 2003. Postretirement benefits costs for all plans were $155 million in 2005, $125 million in 2004, and $118 million in 2003. Pension and postretirement benefits costs for 2005 are calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on our plan assets of 9.0%. In developing our expected long-term rate of return assumption, we evaluated input from our consultants, including their review of asset class risk and return expectations as well as inflation assumptions. Projected returns are based on broad equity and bond markets. Our 2006 expected long-term rate of return on plan assets is based on an asset allocation assumption utilizing active investment management of 66% in equity markets, 25% in fixed income markets, and 9% invested in other assets. Because of market volatility, we periodically review our asset allocation and rebalance our portfolio when considered appropriate. Given market conditions, we believe that 8.75% is a reasonable long-term rate of return on our plan assets for 2006. We will continue to evaluate our actuarial assumptions, including our expected rate of return, at least annually.

We base our determination of the expected return on qualified plan assets on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes changes in fair value in a systematic manner over a three-year period. Accordingly, the future value of assets will be impacted as previously deferred gains or losses are recorded. We have unrecognized net losses due to the performance of the financial markets. As of December 31, 2005, we had $6 million of cumulative losses that remain to be recognized in the calculation of the market-related value of assets.

The discount rate that we utilize for determining future pension and postretirement benefit obligations is based on a yield curve approach and a review of bonds that receive one of the two highest ratings given by a recognized rating agency. The yield curve approach matches projected plan pension and postretirement benefit payment streams with bond portfolios reflecting actual liability duration unique to our plans. The discount rate determined on this basis decreased from 6.0% at December 31, 2004 to 5.9% at December 31, 2005. Due to recent financial market performance, lower discount rates and increased health care trend rates, we estimate that our 2006 pension costs will approximate $80 million compared to $96 million in 2005 and our 2006 postretirement benefit costs will approximate $192 million compared to $155 million in 2005. In the last several years, we have made modifications to the pension and postretirement benefit plans to mitigate the earnings impact of higher costs. Future actual pension and postretirement benefit costs will depend on future investment performance, changes in future discount rates and various other factors related to plan design. Additionally, future pension costs for Detroit Edison will be affected by a pension tracking mechanism, which was authorized by the MPSC in its November 2004 rate order. The tracking mechanism provides for the recovery or refunding of pension costs above or below the amount reflected in Detroit Edison's base rates. In April 2005, the MPSC approved the deferral of the non-capitalized portion of MichCon's negative pension expense. MichCon will record a regulatory liability for any negative pension costs, as determined under generally accepted accounting principles.

Lowering the expected long-term rate of return on our plan assets by one-percentage-point would have increased our 2005 qualified pension costs by approximately $24 million. Lowering the discount rate and the salary increase assumptions by one-percentage-point would have increased our 2005 pension costs by approximately $10 million. Lowering the health care cost trend assumptions by one-percentage-point would have decreased our postretirement benefit service and interest costs for 2005 by approximately $20 million.

The market value of our pension and postretirement benefit plan assets has been affected by the financial markets. The value of our plan assets increased from $2.9 billion at December 31, 2003 to $3.3 billion at December 31, 2004. The value at December 31, 2005 was $3.3 billion. The investment performance returns and declining discount rates required us to recognize an additional minimum pension liability, an intangible asset and an entry to other comprehensive loss (shareholders' equity) in 2003, 2004, and 2005. The additional minimum pension liability and related accounting entries will be reversed on the balance sheet in future periods if the fair value of plan assets exceeds the accumulated pension benefit obligations. The recording of the minimum pension liability does not affect net income or cash flow.

Pension and postretirement costs and pension cash funding requirements may increase in future years without substantial returns in the financial markets. We made a $222 million cash contribution in 2003 and a $170 million contribution to our pension plan in the form of DTE Energy common stock in 2004. We did not make pension contributions in 2005. We contributed $80 million to our postretirement plans in 2004. We did not contribute to our postretirement plans in 2003 and 2005. We do not anticipate making a contribution to our qualified pension plans in 2006. At the discretion of management, we may make up to a $120 million contribution to our postretirement plans in 2006.

In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act was signed into law. This Act provides for a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to the benefit established by law. The effects of the subsidy on the measurement of net periodic postretirement benefit costs reduced costs by $20 million in 2005 and $16 million in 2004.

See Note 14.

Allowance for Doubtful Accounts

We establish an allowance for doubtful accounts based upon factors surrounding the credit risk of specific customers, historical trends, economic conditions, age of receivables and other information. Higher customer bills due to increased gas prices, the lack of adequate levels of assistance for low-income customers and economic conditions have also contributed to the increase in past due receivables. As a result of these factors, our allowance for doubtful accounts increased in 2004 and 2005. We believe the allowance for doubtful accounts is based on reasonable estimates. As part of the 2005 rate order for MichCon, the MPSC provided for the establishment of an uncollectible accounts tracking mechanism that partially mitigates the impact associated with MichCon uncollectible expenses. However, failure to make continued progress in collecting our past due receivables in light of rising energy prices would unfavorably affect operating results and cash flow.

Legal and Tax Reserves

We are involved in various legal and tax proceedings, claims and litigation arising in the ordinary course of business. We regularly assess our liabilities and contingencies in connection with asserted or potential matters, and establish reserves when appropriate. Legal reserves are based upon management's assessment of pending and threatened legal proceedings and claims against the Company. Tax reserves are based upon management's assessment of potential adjustments to tax positions taken. We regularly review ongoing tax audits and prior audit experience, in addition to current tax and accounting authority in assessing potential adjustments.

ENVIRONMENTAL MATTERS

Protecting the environment, as well as correcting past environmental damage, continues to be a focus of state and federal regulators. Legislation and/or rulemaking could further impact the electric utility industry including Detroit Edison. The EPA and the MDEQ have aggressive programs to clean-up contaminated property.

Electric Utility

Air - Detroit Edison is subject to EPA ozone transport and acid rain regulations that limit power plant emissions of sulfur dioxide and nitrogen oxides. In March 2005, EPA issued additional emission reduction regulations relating to ozone, fine particulate, regional haze and mercury air pollution. The new rules will lead to additional controls on fossil-fueled power plants to reduce nitrogen oxide, sulfur dioxide and mercury emissions. To comply with these requirements, Detroit Edison has spent approximately $644 million through 2005. We estimate Detroit Edison will incur future capital expenditures of up to $218 million in 2006 and up to $2.2 billion of additional capital expenditures through 2018 to satisfy both the existing and proposed new control requirements. Under the June 2000 Michigan restructuring legislation, beginning January 1, 2004, annual return of and on this capital expenditure was deferred in ratemaking until December 31, 2005, the expiration of the rate cap period.

The EPA has ongoing enforcement actions against several major electric utilities citing violations of new source provisions of the Clean Air Act. Detroit Edison received and responded to information requests from the EPA on this subject. The EPA has not initiated proceedings against Detroit Edison. In October 2003, the EPA promulgated revised regulations to clarify new source review provisions going forward. Several states and environmental organizations have challenged these regulations and, in December 2003, a stay was issued until the U.S. Court of Appeals D.C. Circuit renders an opinion in the case. We cannot predict the future impact of this issue upon Detroit Edison.

Water - Detroit Edison is required to examine alternatives for reducing the environmental impacts of the cooling water intake structures at several of its facilities. Based on the results of the studies to be conducted over the next several years, Detroit Edison may be required to install additional control technologies to reduce the impacts of the intakes. It is estimated that we will incur up to $50 million over the next four to six years in additional capital expenditures to comply with these requirements.

Contaminated Sites - Detroit Edison conducted remedial investigations at contaminated sites, including two former MGP sites, the area surrounding an ash landfill and several underground and aboveground storage tank locations. We have a reserve balance of $13 million as of December 31, 2005 for the remediation of these sites over the next several years.

Gas Utility

Contaminated Sites - Prior to the construction of major interstate natural gas pipelines, gas for heating and other uses was manufactured locally from processes involving coal, coke or oil. Gas Utility owns, or previously owned, 15 former MGP sites. Investigations have revealed contamination related to the by-products of gas manufacturing at each site. In addition to the MPG sites, Gas Utility is also in the process of cleaning up other contaminated sites. Cleanup activities associated with these sites will be conducted over the next several years. As a result of these determinations, we have recorded liabilities of $35 million and $1 million for the MGPs and other contaminated sites, respectively. It is estimated that Gas Utility may incur $5 million in expenses related to cleanup costs in 2006. While we cannot make any assurances, we believe that a cost deferral and rate recovery mechanism for the MGP sites, approved by the MPSC, will prevent these costs from having a material adverse impact on our results of operations.

In 1993, a cost deferral and rate recovery mechanism was approved by the MPSC for investigation and remediation costs incurred at former MGP sites in excess of this reserve. Gas Utility employed outside consultants to evaluate remediation alternatives for these sites, to assist in estimating its potential liabilities and to review its archived insurance policies. As a result of these studies, Gas Utility accrued an additional liability and a corresponding regulatory asset of $35 million during 1995. During 2005, we spent approximately $4 million investigating and remediating these former MGP sites. In December 2005, we retained multiple environmental consultants to estimate the projected cost to remediate each

MGP site. We accrued an additional $9 million in remediation liabilities associated with two of our MGP sites, to increase the reserve balance to $35 million at December 31, 2005.

Any significant change in assumptions, such as remediation techniques, nature and extent of contamination and regulatory requirements, could impact the estimate of remedial action costs for the sites and thereby affect the Company's financial position and cash flows. However, we anticipate the cost deferral and rate recovery mechanism approved by the MPSC will prevent environmental costs from having a material adverse impact on our results of operations.

Other

Our non-utility affiliates are subject to a number of environmental laws and regulations dealing with the protection of the environment from various pollutants. We are in the process of installing new environmental equipment at our coke battery facilities in Michigan. We expect the projects to be completed within two years at a cost of approximately $25 million. Our other non-utility affiliates are substantially in compliance with all environmental requirements.

Various state and federal laws regulate our handling, storage and disposal of waste materials. The EPA and the MDEQ have aggressive programs to manage the clean up of contaminated property. We have extensive land holdings and, from time to time, must investigate claims of improperly disposed contaminants. We anticipate our utility and non-utility companies may periodically be included in various types of environmental proceedings.

DTE2

In 2003, we began the development of DTE2, an enterprise resource planning (ERP) system initiative to improve existing processes and to implement new core information systems, relating to finance, human resources, supply chain and work management. As part of this initiative, we are implementing Enterprise Business Systems software including, among others, products developed by SAP AG and MRO Software, Inc. The first phase of implementation occurred in 2005 in the regulated electric fossil generation unit. Full implementation throughout the Company is not anticipated until 2007. The conversion of data and the implementation and operation of the ERP will be continuously monitored and reviewed and should ultimately strengthen our internal control structure and lead to increased cost efficiencies. Although our implementation plan includes detailed testing and contingency arrangements to ensure a smooth and successful transition, we can provide no assurance that complications will not arise that could interrupt our operations.

We have spent approximately $210 million through the end of 2005 and expect total spending over the life of the project to be between $375 million and $400 million. We expect the benefits of lower costs, faster business cycles, repeatable and optimized processes, enhanced internal controls, improvements in inventory management and reductions in system support costs to outweigh the expense of our investment in this initiative.

MIDWEST INDEPENDENT SYSTEM OPERATOR (MISO)

The MISO was formed in 1996 by its member transmission owners and in December 2001 received FERC approval as a Regional Transmission Organization (RTO) authorized to provide regional transmission services as prescribed by FERC in its Order 2000. Order 2000 requires an RTO to perform eight functions, including tariff administration, transmission system congestion management, provision of ancillary services to support transmission operations, market monitoring, interregional coordination and the coordination of system planning and expansion. MISO's independence from ownership of either generation or transmission facilities is intended to enable it to ensure fair access to the transmission grid, and through its congestion management role, MISO is also charged with ensuring grid reliability. MISO's initial provision of transmission services in December 2001 was known as Day 1 operations.

In keeping with Order 2000, which permits RTOs to provide real-time energy imbalance services and a market-based mechanism for congestion management, MISO, on April 1, 2005, launched its Midwest Energy Market, or Day 2 operations, and began regional wholesale electric market operations and transmission service throughout its area. A key feature of the Midwest Energy Market is the establishment of Locational Marginal Prices (LMPs) which provide price transparency for the sale and purchase of wholesale electricity at different locations in the market territory. The LMP is the market clearing price at a specific pricing location in the Midwest Energy Market that is equal to the cost of supplying the next increment of load at that location. The value of an LMP is the same whether a purchase or sale is made at that location. Detroit Edison participates in the Midwest Energy Market by offering its generation on a day-ahead and real time basis and by bidding for power in the market to serve its load. The cost of power procured from the market net of any gain realized from generation sold into the market is included and recovered through the PSCR mechanism. In addition, LMPs are expected to encourage new generation to locate where the power produced is of most value to the load and is expected to identify where new transmission facilities are needed to relieve grid congestion.

MISO is compensated for assuring grid reliability and for supporting the energy market through FERC-approved rates charged to load. Detroit Edison became a non-transmission owning member of MISO in compliance with section 10w (1) of PA 141. The MPSC has ordered that MISO costs charged to Detroit Edison should be recovered through the PSCR mechanism.

FEDERAL ENERGY POLICY ACT OF 2005

In August 2005, the Energy Policy Act of 2005 (Energy Act) was signed into law. Among other provisions, the Energy Act:

- establishes mandatory electric reliability standards;
- repeals the Public Utility Holding Company Act of 1935;
- renews the Price Anderson Act for twenty years which provides liability protection for nuclear power plants;
- increases funding levels for the Low-Income Home Energy Assistance Program; and
- increases FERC oversight responsibilities for the electric utility industry.

The implementation of the Energy Act requires proceedings at the state level and development of regulations by the FERC, as well as other federal agencies. The impact of the Energy Act on our results of operations will depend on the implementation of final rules and cannot be fully determined at this time.

NEW ACCOUNTING PRONOUNCEMENTS

See Note 2— New Accounting Pronouncements for discussion of new pronouncements .

FAIR VALUE OF CONTRACTS

The following disclosures are voluntary and provide enhanced transparency of the derivative activities and position of our trading businesses and our other businesses.

We use the criteria in Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended and interpreted, to determine if certain contracts must be accounted for as derivative instruments. The rules for determining whether a contract meets the criteria for derivative accounting are numerous and complex. Moreover, significant judgment is required to determine whether a contract requires derivative accounting, and similar contracts can sometimes be accounted for differently. If a contract is accounted for as a derivative instrument, it is recorded in the financial statements as “assets or liabilities from risk management and trading activities”, at the fair value of the contract. The recorded fair value of the contract is then adjusted quarterly to reflect any change in the fair value of the contract, a practice known as mark to market (MTM) accounting.

Fair value represents the amount at which willing parties would transact an arms-length transaction. To determine the fair value of contracts accounted for as derivative instruments, we use a combination of quoted market prices and mathematical valuation models. Valuation models require various inputs, including forward prices, volatility, interest rates, and exercise periods.

Contracts we typically classify as derivative instruments are power, gas and oil forwards, futures, options and swaps, as well as foreign currency contracts. Items we do not generally account for as derivatives (and which are therefore excluded from the following tables) include gas inventory, gas storage and transportation arrangements, full-requirements power contracts and gas and oil reserves. As subsequently discussed, we have fully reserved the value of derivative contracts beyond the liquid trading timeframe thereby not impacting income.

The subsequent tables contain the following four categories represented by their operating characteristics and key risks.

- “Proprietary Trading” represents derivative activity transacted with the intent of taking a view, capturing market price changes, or putting capital at risk. This activity is speculative in nature as opposed to hedging an existing exposure.
- “Structured Contracts” represents derivative activity transacted with the intent to capture profits by originating substantially hedged positions with wholesale energy marketers, utilities, retail aggregators and alternative energy suppliers. Although transactions are generally executed with a buyer and seller simultaneously, some positions remain open until a suitable offsetting transaction can be executed.
- “Economic Hedges” represents derivative activity associated with assets owned and contracted by DTE Energy, including forward sales of gas production and trades associated with owned transportation and storage capacity. Changes in the value of derivatives in this category economically offset changes in the value of underlying non-derivative positions, which do not qualify for fair value accounting. The difference in accounting treatment of derivatives in this category and the underlying non-derivative positions can result in significant earnings volatility as discussed in more detail in the preceding Results of Operations section.
- “Other Non-Trading Activities” primarily represent derivative activity associated with our Michigan gas reserves and synfuel operations. A substantial portion of the price risk associated with the gas reserves has been mitigated through 2013. Changes in the value of the hedges are recorded as “assets or liabilities from risk management and trading activities”, with an offset in other comprehensive income to the extent that the hedges are deemed effective. Oil-related derivative contracts have been executed to economically hedge cash flow risks related to underlying, non-derivative synfuel related positions through 2007. The amounts shown in the following tables exclude the value of the underlying gas reserves and synfuel proceeds including changes therein.

Roll-Forward of Mark to Market Energy Contract Net Assets

The following tables provide details on changes in our mark to market net asset or (liability) position during 2005:

(in Millions)	Trading Activities: Proprietary Trading	Trading Activities: Structured Contracts	Trading Activities: Economic Hedges	Trading Activities: Total	Other Non-Trading Activities	Total
MTM at December 31, 2004	$ 3	$ 23	$ (98)	$ (72)	$ (100)	$ (172)
Reclassed to realized upon settlement	(2)	(16)	32	14	66	80
Changes in fair value recorded to income	6	(91)	(58)	(143)	43	(100)
Amortization of option premiums	—	—	(3)	(3)	(26)	(29)
Amounts recorded to unrealized income	4	(107)	(29)	(132)	83	(49)
Amounts recorded in OCI (Note 1)	—	(54)	17	(37)	(187)	(224)
Option premiums paid and other	(115)	2	—	(113)	64	(49)
MTM at December 31, 2005	$ (108)	$ (136)	$ (110)	$ (354)	$ (140)	$ (494)

The following table provides a current and noncurrent analysis of "assets and liabilities from risk management and trading activities", as reflected in the consolidated statement of financial position as of December 31, 2005. Amounts that relate to contracts that become due within twelve months are classified as current and all remaining amounts are classified as noncurrent.

(in Millions)	Trading Activities: Proprietary Trading	Trading Activities: Structured Contracts	Trading Activities: Economic Hedges	Trading Activities: Eliminations	Trading Activities: Totals	Other Non-Trading Activities	Total Assets (Liabilities)
Current assets	$ 295	$ 161	$ 205	$ (3)	$ 658	$ 148	$ 806
Noncurrent assets	9	53	186	(6)	242	74	316
Total MTM assets	304	214	391	(9)	900	222	1,122
Current liabilities	(359)	(232)	(301)	3	(889)	(200)	(1,089)
Noncurrent liabilities	(53)	(118)	(200)	6	(365)	(162)	(527)
Total MTM liabilities	(412)	(350)	(501)	9	(1,254)	(362)	(1,616)
Total MTM net assets (liabilities)	$ (108)	$ (136)	$ (110)	$ —	$ (354)	$ (140)	$ (494)

Maturity of Fair Value of MTM Energy Contract Net Assets

We fully reserve all unrealized gains and losses related to periods beyond the liquid trading timeframe. Our intent is to recognize MTM activity only when pricing data is obtained from active quotes and published indexes. Actively quoted and published indexes include exchange traded (i.e., NYMEX) and over-the-counter positions for which broker quotes are available. Although the NYMEX has currently quoted prices for the next 72 months, broker quotes for gas and power are generally available for 18 and 24 months into the future, respectively, we fully reserve all unrealized gains and losses related to periods beyond the liquid trading timeframe and which therefore do not impact income.

As a result of adherence to generally accepted accounting principles, the tables above do not include the expected favorable earnings impacts of certain non-derivative gas storage and power contracts. We entered into economically favorable transactions in early 2005 to delay previously planned withdrawals from gas storage due to a decrease in the current price for natural gas and an increase in the forward price for natural gas. We anticipate the financial impact of this timing difference will reverse when the gas is withdrawn from storage in the current storage cycle and is sold at prices significantly in excess of the cost of gas in storage. In addition, we entered into forward power contracts to economically hedge certain physical and capacity power contracts. We expect the timing difference on the forward power contracts will be fully realized by the end of 2007.

The table below shows the maturity of our MTM positions:

(in Millions) **Source of Fair Value**	2006	2007	2008	Total Fair Value
Proprietary Trading	$ (64)	$ (44)	$ —	$ (108)
Structured Contracts	(71)	(61)	(4)	(136)
Economic Hedges	(96)	(4)	(10)	(110)
Total Trading Activities	(231)	(109)	(14)	(354)
Other Non-Trading Activities	(52)	(63)	(25)	(140)
Total	$ (283)	$ (172)	$ (39)	$ (494)

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

DTE Energy has commodity price risk arising from market price fluctuations in conjunction with the anticipated purchases of coal, uranium, and electricity to meet its obligations during periods of peak demand. We also are exposed to the risk of market price fluctuations on gas sale and purchase contracts, gas production and gas inventories. To limit our exposure to commodity price fluctuations, we have entered into a series of electricity and gas futures, forwards, option and swap contracts. Commodity price risk associated with our electric and gas utilities is limited due to the PSCR and GCR mechanisms. See Note 1.

Our Coal-Based Fuels and Landfill Gas Recovery businesses are also subject to crude oil price risk. As previously discussed, production tax credits generated by DTE Energy’s synfuel, coke battery and landfill gas recovery operations are subject to phase-out if domestic crude oil prices reach certain levels. We have entered into a series of derivative contracts for 2006 through 2007 to economically hedge the impact of oil prices on a portion of our synfuel cash flow.

See Note 12.

Credit Risk

Bankruptcies

We purchase and sell electricity, gas, coal, coke and other energy products from and to numerous companies operating in the steel, automotive, energy, retail and other industries. Certain of our customers have filed for bankruptcy protection under Chapter 11 of the U. S. Bankruptcy Code. We regularly review contingent matters relating to these customers and our purchase and sale contracts and we record provisions for amounts considered at risk of probable loss. We believe our previously accrued amounts are adequate for probable loss. The final resolution of these matters is not expected to have a material effect on our financial statements.

Other

We engage in business with customers that are non-investment grade. We closely monitor the credit ratings of these customers and, when deemed necessary, we request collateral or guarantees from such customers to secure their obligations.

We utilize both external and internally generated credit assessments when determining the credit quality of our trading counterparties. The following table displays the credit quality of our trading counterparties as of December 31, 2005:

(in Millions)	Credit Exposure before Cash Collateral	Cash Collateral	Net Credit Exposure
Investment Grade (1)			
A- and Greater	$ 444	$ (46)	$ 398
BBB+ and BBB	290	(9)	281
BBB-	17	—	17
Total Investment Grade	751	(55)	696
Non-investment grade (2)	52	(13)	39
Internally Rated — investment grade (3)	129	(9)	120
Internally Rated — non-investment grade (4)	11	—	11
Total	$ 943	$ (77)	$ 866

(1) This category includes counterparties with minimum credit ratings of Baa3 assigned by Moody's Investors Service (Moody's) and BBB- assigned by Standard & Poor's Rating Group (Standard & Poor's). The five largest counterparty exposures combined for this category represented 29% of the total gross credit exposure.

(2) This category includes counterparties with credit ratings that are below investment grade. The five largest counterparty exposures combined for this category represented less than 5% of the total gross credit exposure.

(3) This category includes counterparties that have not been rated by Moody's or Standard & Poor's, but are considered investment grade based on DTE Energy's evaluation of the counterparty's creditworthiness. The five largest counterparty exposures combined for this category represented 7% of the total gross credit exposure.

(4) This category includes counterparties that have not been rated by Moody's or Standard & Poor's, and are considered non-investment grade based on DTE Energy's evaluation of the counterparty's creditworthiness. The five largest counterparty exposures combined for this category represented less than 1% of the gross credit exposure.

Interest Rate Risk

DTE Energy is subject to interest rate risk in connection with the issuance of debt and preferred securities. In order to manage interest costs, we use treasury locks and interest rate swap agreements. Our exposure to interest rate risk arises primarily from changes in U.S. Treasury rates, commercial paper rates and London Inter-Bank Offered Rates (LIBOR). As of December 31, 2005, the Company has a floating rate debt to total debt ratio of approximately 15% (excluding securitized debt).

Foreign Currency Risk

DTE Energy has foreign currency exchange risk arising from market price fluctuations associated with fixed priced contracts. These contracts are denominated in Canadian dollars and are primarily for the purchase and sale of power as well as for long-term transportation capacity. To limit our exposure to foreign currency fluctuations, we have entered into a series of currency forward contracts through 2008. Additionally, we may enter into fair value currency hedges to mitigate changes in the value of contracts or loans.

Summary of Sensitivity Analysis

We performed a sensitivity analysis to calculate the fair values of our commodity contracts, long-term debt instruments and foreign currency forward contracts. The sensitivity analysis involved increasing and decreasing forward rates at December 31, 2005 by a hypothetical 10% and calculating the resulting change in the fair values. The results of the sensitivity analysis calculations follow:

(in Millions) Activity	Assuming a 10% increase in rates	Assuming a 10% decrease in rates	Change in the fair value of
Gas Contracts	$ (9)	$ 7	Commodity contracts and options
Power Contracts	$ (20)	$ 21	Commodity contracts
Oil Contracts	$ 39	$ (40)	Commodity options
Interest Rate Risk	$ (296)	$ 318	Long-term debt
Foreign Currency Risk	$ 3	$ (3)	Forward contracts

Item 8. Financial Statements and Supplementary Data

The following consolidated financial statements and schedules are included herein.

CONTROLS AND PROCEDURES

(a) Evaluation of disclosure controls and procedures

Management of the Company carried out an evaluation, under the supervision and with the participation of DTE Energy's Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of December 31, 2005, which is the end of the period covered by this report. Based on this evaluation, the Company's Chief Executive Officer and Chief Financial Officer have concluded that such controls and procedures are effective in ensuring that information required to be disclosed by the Company in reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is accumulated and communicated to the Company's management, including its Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure. Due to the inherent limitations in the effectiveness of any disclosure controls and procedures, management cannot provide absolute assurance that the objectives of its disclosure controls and procedures will be attained.

(b) Management's report on internal control over financial reporting

The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control system was designed to provide reasonable assurance to the Company's management and Board of Directors regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Projections of any evaluation of the effectiveness to future periods are subject to the risks that control may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Company's management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2005. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control —Integrated Framework.* Based on our assessment, management believes that, as of December 31, 2005, the Company's internal control over financial reporting was effective based on those criteria.

Management's assessment of the effectiveness of the Company's internal control over financial reporting has been audited by the Company's independent registered public accounting firm, as stated in their report which is included herein.

(c) Changes in internal control over financial reporting

The Company has established a formal assessment process and related procedures to evaluate the effectiveness of internal control over financial reporting using criteria specified by COSO. The assessment process is comprehensive in scope, utilizes internal and external resources and involves many individuals at various levels of the Company in the design, testing and evaluation of internal control.

As part of the evaluation and assessment process, the Company has been improving the design and operating effectiveness of many entity-level and process-level controls. Control testing and remediation activities provide reasonable, but not absolute, assurance that a material weakness in internal control over financial reporting will be avoided. The inherent limitations of our current internal controls, a portion of which are manual by their nature, contribute to the potential for control deficiencies. Management does not believe any areas requiring further improvement constitute a material weakness in internal control over financial reporting as of December 31, 2005.

On October 1, 2005, DTE Energy's Fuel Transportation and Marketing unit completed its implementation of a deal capture and risk management system which impacted various processes and controls related to transaction capture, confirmation, transaction valuation and risk management. The final implementation of power transactions replaced outdated legacy computer systems. In connection with the implementation of this system, DTE Energy has implemented new processes and modified existing processes to facilitate added efficiencies and system-based controls. The impact of the new system may be considered a material change in internal controls over financial reporting. With the exception of this change, there has been no change in the Company's internal control over financial reporting during the fourth quarter of 2005 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of DTE Energy Company:

We have audited management's assessment, included in the accompanying Management's report on internal control over financial reporting, that DTE Energy Company and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

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

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

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of the Company as of December 31, 2005 and for the year then ended, and the financial statement schedule; and our report dated March 7, 2006 expressed an unqualified opinion on those consolidated financial statements and financial statement schedule.

/S/ DELOITTE & TOUCHE LLP

Detroit, Michigan
March 7, 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of DTE Energy Company:

We have audited the consolidated statement of financial position of DTE Energy Company and subsidiaries (the "Company") as of December 31, 2005 and 2004, and the related consolidated statements of operations, cash flows, and changes in shareholders' equity and comprehensive income for each of the three years in the period ended December 31, 2005. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements and financial statement schedule based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of DTE Energy Company and subsidiaries at December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005 in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements of the Company taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 2 to the consolidated financial statements, in connection with the required adoption of certain new accounting principles, in 2005 the Company changed its method of accounting for asset retirement obligations and in 2003 the Company changed its method of accounting for asset retirement obligations, energy trading contracts and gas inventories.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2005, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 7, 2006 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/S/ DELOITTE & TOUCHE LLP

Detroit, Michigan
March 7, 2006

DTE Energy Company
Consolidated Statement of Operations

(in Millions, Except per Share Amounts)	Year Ended December 31 2005	2004	2003
Operating Revenues	**$ 9,022**	$ 7,071	$ 7,005
Operating Expenses			
Fuel, purchased power and gas	**3,530**	2,007	2,241
Operation and maintenance	**3,793**	3,355	3,055
Depreciation, depletion and amortization	**869**	742	685
Taxes other than income	**274**	312	334
Asset (gains) and losses, net	**(390)**	(215)	(77)
	8,076	6,201	6,238
Operating Income	**946**	870	767
Other (Income) and Deductions			
Interest expense	**519**	516	545
Interest income	**(57)**	(55)	(37)
Other income	**(68)**	(81)	(110)
Other expenses	**55**	67	82
	449	447	480
Income Before Income Taxes and Minority Interest	**497**	423	287
Income Tax Provision (Benefit) (Note 7)	**202**	174	(116)
Minority Interest	**(281)**	(212)	(91)
Income from Continuing Operations	**576**	461	494
Income (Loss) from Discontinued Operations, net of tax (Note 3)	**(36)**	(30)	54
Cumulative Effect of Accounting Changes, net of tax (Note 2)	**(3)**	—	(27)
Net Income	**$ 537**	$ 431	$ 521
Basic Earnings per Common Share (Note 8)			
Income from continuing operations	**$ 3.29**	$ 2.67	$ 2.95
Discontinued operations	**(.20)**	(.17)	.33
Cumulative effect of accounting changes	**(.02)**	—	(.17)
Total	**$ 3.07**	$ 2.50	$ 3.11
Diluted Earnings per Common Share (Note 8)			
Income from continuing operations	**$ 3.27**	$ 2.66	$ 2.93
Discontinued operations	**(.20)**	(.17)	.32
Cumulative effect of accounting changes	**(.02)**	—	(.16)
Total	**$ 3.05**	$ 2.49	$ 3.09
Average Common Shares			
Basic	**175**	173	168
Diluted	**176**	173	168
Dividends Declared per Common Share	**$ 2.06**	$ 2.06	$ 2.06

See Notes to Consolidated Financial Statements

DTE Energy Company
Consolidated Statement of Financial Position

(in Millions)	December 31 2005	December 31 2004
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 88**	$ 56
Restricted cash (Note 1)	**122**	126
Accounts receivable		
Customer (less allowance for doubtful accounts of $136 and $129, respectively)	**1,288**	865
Accrued unbilled revenues	**458**	378
Collateral held by others	**286**	44
Other	**549**	354
Inventories		
Fuel and gas	**522**	509
Materials and supplies	**146**	159
Deferred income taxes	**257**	94
Assets from risk management and trading activities	**806**	296
Other	**160**	115
	4,682	2,996
Investments		
Nuclear decommissioning trust funds	**646**	590
Other	**530**	558
	1,176	1,148
Property		
Property, plant and equipment	**18,660**	18,011
Less accumulated depreciation and depletion (Notes 1 and 2)	**(7,830)**	(7,520)
	10,830	10,491
Other Assets		
Goodwill	**2,057**	2,067
Regulatory assets (Note 4)	**2,074**	2,119
Securitized regulatory assets (Note 4)	**1,340**	1,438
Notes receivable	**409**	529
Assets from risk management and trading activities	**316**	125
Prepaid pension assets	**186**	184
Other	**265**	200
	6,647	6,662
Total Assets	**$ 23,335**	$ 21,297

See Notes to Consolidated Financial Statements

DTE Energy Company
Consolidated Statement of Financial Position

(in Millions, Except Shares)	December 31 2005	December 31 2004
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	**$ 1,187**	$ 892
Accrued interest	**115**	111
Dividends payable	**92**	90
Accrued payroll	**34**	33
Income taxes	**—**	16
Short-term borrowings	**943**	403
Current portion long-term debt, including capital leases	**691**	514
Liabilities from risk management and trading activities	**1,089**	369
Other	**769**	581
	4,920	3,009
Other Liabilities		
Deferred income taxes	**1,396**	1,124
Regulatory liabilities (Notes 2 and 4)	**715**	817
Asset retirement obligations (Note 2)	**1,091**	916
Unamortized investment tax credit	**131**	143
Liabilities from risk management and trading activities	**527**	224
Liabilities from transportation and storage contracts	**317**	387
Accrued pension liability	**284**	265
Deferred gains from asset sales	**188**	414
Minority interest	**92**	132
Nuclear decommissioning (Notes 2 and 5)	**85**	77
Other	**740**	635
	5,566	5,134
Long-Term Debt (net of current portion) (Note 9)		
Mortgage bonds, notes and other	**5,234**	5,673
Securitization bonds	**1,295**	1,400
Equity-linked securities	**175**	178
Trust preferred-linked securities	**289**	289
Capital lease obligations	**87**	66
	7,080	7,606
Commitments and Contingencies (Notes 4, 5 and 13)		
Shareholders' Equity		
Common stock, without par value, 400,000,000 shares authorized, 177,814,429 and 174,209,034 shares issued and outstanding, respectively	**3,483**	3,323
Retained earnings	**2,557**	2,383
Accumulated other comprehensive loss	**(271)**	(158)
	5,769	5,548
Total Liabilities and Shareholders' Equity	**$ 23,335**	$ 21,297

See Notes to Consolidated Financial Statements

DTE Energy Company
Consolidated Statement of Cash Flows

(in Millions)	Year Ended December 31 2005	2004	2003
Operating Activities			
Net income	**$ 537**	$ 431	$ 521
Adjustments to reconcile net income to net cash from operating activities:			
Depreciation, depletion and amortization	**872**	744	691
Deferred income taxes	**147**	129	(220)
Gain on sale of interests in synfuel projects	**(367)**	(219)	(83)
Gain on sale of ITC and other assets, net	**(38)**	(17)	(145)
Partners' share of synfuel project losses	**(318)**	(223)	(78)
Restructuring charges	**33**	—	—
Contributions from synfuel partners	**243**	141	65
Cumulative effect of accounting changes	**3**	—	27
Changes in assets and liabilities, exclusive of changes shown separately (Note 1)	**(111)**	9	172
Net cash from operating activities	**1,001**	995	950
Investing Activities			
Plant and equipment expenditures – utility	**(850)**	(815)	(679)
Plant and equipment expenditures – non-utility	**(215)**	(89)	(72)
Acquisitions, net of cash acquired	**(50)**	—	—
Proceeds from sale of interests in synfuel projects	**349**	221	89
Proceeds from sale of ITC and other assets, net of cash divested	**60**	104	669
Restricted cash for debt redemptions	**4**	5	106
Proceeds from sale of nuclear decommissioning trust fund assets	**201**	254	199
Investment in nuclear decommissioning trust funds	**(235)**	(287)	(231)
Other investments	**(66)**	(74)	(71)
Net cash from (used for) investing activities	**(802)**	(681)	10
Financing Activities			
Issuance of long-term debt	**869**	736	527
Redemption of long-term debt	**(1,266)**	(759)	(1,208)
Short-term borrowings, net	**437**	33	(44)
Issuance of common stock	**172**	41	44
Repurchase of common stock	**(13)**	—	—
Dividends on common stock	**(360)**	(354)	(346)
Other	**(6)**	(9)	(12)
Net cash used for financing activities	**(167)**	(312)	(1,039)
Net Increase (Decrease) in Cash and Cash Equivalents	**32**	2	(79)
Cash and Cash Equivalents at Beginning of Period	**56**	54	133
Cash and Cash Equivalents at End of Period	**$ 88**	$ 56	$ 54

See Notes to Consolidated Financial Statements

DTE Energy Company
Consolidated Statement of Changes in Shareholders' Equity and Comprehensive Income

(Dollars in Millions, Shares in Thousands)	Common Stock Shares	Common Stock Amount	Retained Earnings	Accumulated Other Comprehensive Loss	Total
Balance, December 31, 2002	167,462	$ 3,052	$ 2,132	$ (619)	$ 4,565
Net income	—	—	521	—	521
Issuance of new shares	1,225	57	—	—	57
Dividends declared on common stock	—	—	(348)	—	(348)
Repurchase and retirement of common stock	(80)	(1)	—	—	(1)
Pension obligations (Note 14)	—	—	—	420	420
Net change in unrealized losses on derivatives, net of tax	—	—	—	17	17
Net change in unrealized gains on investments, net of tax	—	—	—	52	52
Unearned stock compensation and other	—	1	3	—	4
Balance, December 31, 2003	168,607	3,109	2,308	(130)	5,287
Net income	—	—	431	—	431
Issuance of new shares	5,671	223	—	—	223
Dividends declared on common stock	—	—	(357)	—	(357)
Repurchase and retirement of common stock	(69)	(3)	—	—	(3)
Pension obligations (Note 14)	—	—	—	7	7
Net change in unrealized losses on derivatives, net of tax	—	—	—	(15)	(15)
Net change in unrealized losses on investments, net of tax	—	—	—	(20)	(20)
Unearned stock compensation and other	—	(6)	1	—	(5)
Balance, December 31, 2004	174,209	3,323	2,383	(158)	5,548
Net income	—	—	537	—	537
Issuance of new shares	3,686	172	—	—	172
Dividends declared on common stock	—	—	(363)	—	(363)
Repurchase and retirement of common stock	(288)	(13)			(13)
Pension obligations (Note 14)	—	—	—	4	4
Net change in unrealized losses on derivatives, net of tax	—	—	—	(106)	(106)
Net change in unrealized losses on investments, net of tax	—	—	—	(11)	(11)
Unearned stock compensation and other	207	1	—	—	1
Balance, December 31, 2005	**177,814**	**$ 3,483**	**$ 2,557**	**$ (271)**	**$ 5,769**

The following table displays comprehensive income (loss):

(in Millions)	2005	2004	2003
Net income	**$ 537**	$ 431	$ 521
Other comprehensive income (loss), net of tax:			
Pension obligations, net of taxes of $2, $4 and $226 (Notes 4 and 14)	**4**	7	420
Net unrealized losses on derivatives:			
Gains (losses) arising during the period, net of taxes of $(78), $(26) and $8	**(145)**	(49)	16
Amounts reclassified to income, net of taxes of $21, $18 and $-	**39**	34	1
	(106)	(15)	17
Net unrealized gains (losses) on investments:			
Gains (losses) arising during the period, net of taxes of $(3), $(3) and $28	**(6)**	(5)	52
Amounts reclassified to income, net of taxes of $(2), $(8) and $-	**(5)**	(15)	—
	(11)	(20)	52
Comprehensive income	**$ 424**	$ 403	$ 1,010

See Notes to Consolidated Financial Statements

DTE Energy Company
Notes to Consolidated Financial Statements

NOTE 1 — SIGNIFICANT ACCOUNTING POLICIES

Corporate Structure

DTE Energy owns the following businesses:

- The Detroit Edison Company (Detroit Edison), an electric utility engaged in the generation, purchase, distribution and sale of electric energy to approximately 2.2 million customers in southeast Michigan;
- Michigan Consolidated Gas Company (MichCon), a natural gas utility engaged in the purchase, storage, transmission and distribution and sale of natural gas to approximately 1.3 million customers throughout Michigan; and
- Other non-utility subsidiaries engaged in a variety of energy related businesses such as synfuels, energy services, natural gas exploration and production, energy marketing and trading, coal transportation and gas storage and transportation.

Detroit Edison and MichCon are regulated by the MPSC. The FERC regulates certain activities of Detroit Edison's business as well as various other aspects of businesses under DTE Energy. In addition, we are regulated by other federal and state regulatory agencies including the NRC, the EPA and MDEQ.

References in this report to "we," "us," "our" or "Company" are to DTE Energy and its subsidiaries, collectively.

Principles of Consolidation

We consolidate all majority owned subsidiaries and investments in entities in which we have controlling influence. Non-majority owned investments are accounted for using the equity method when the company is able to influence the operating policies of the investee. Non-majority owned investments include investments in limited liability companies, partnerships or joint ventures. When we do not influence the operating policies of an investee, the cost method is used. We eliminate all intercompany balances and transactions.

For entities that are considered variable interest entities, we apply the provisions of Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 46-R, *Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51.* For a detailed discussion of FIN 46-R, see Note 2.

Basis of Presentation

The accompanying consolidated financial statements are prepared using accounting principles generally accepted in the United States of America. These accounting principles require us to use estimates and assumptions that impact reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. Actual results may differ from our estimates.

We reclassified certain prior year balances to match the current year's financial statement presentation.

Revenues

Revenues from the sale and delivery of electricity, and the sale, delivery and storage of natural gas are recognized as services are provided. Detroit Edison and MichCon record revenues for electric and gas provided but unbilled at the end of each month.

Detroit Edison's accrued revenues include a component for the cost of power sold that is recoverable through the PSCR mechanism. MichCon's accrued revenues include a component for the cost of gas sold that is recoverable through the GCR mechanism. Annual PSCR and GCR proceedings before the MPSC permit Detroit Edison and MichCon to recover prudent and reasonable supply costs. Any overcollection or undercollection of costs, including interest, will be reflected in future rates. Prior to 2004, Detroit Edison's retail rates were frozen under Public Act (PA) 141. Accordingly, Detroit Edison did not accrue revenues under the PSCR mechanism prior to 2004. See Note 4.

Non-utility businesses recognize revenues as services are provided and products are delivered. Our Fuel Transportation and Marketing segment records in revenues net unrealized derivative gains and losses on energy trading contracts, including those to be physically settled.

Gains from Sale of Interests in Synthetic Fuel Facilities

Through December 2005, we have sold interests in all of our synthetic fuel production plants, representing approximately 91% of our total production capacity. Proceeds from the sales are contingent upon production levels, the production qualifying for production tax credits, and the value of such credits. Production tax credits are subject to phase-out if domestic crude oil prices reach certain levels. See Note 13 for further discussion. We recognize gains from the sale of interests in the synfuel facilities as synfuel is produced and sold, and when there is persuasive evidence that the sales proceeds have become fixed or determinable and collectibility is reasonably assured. Until the gain recognition criteria are met, gains from selling interests in synfuel facilities are deferred. It is possible that gains will be deferred in the first, second and/or third quarters of each year until there is persuasive evidence that no tax credit phase out will occur for the applicable calendar year. This could result in shifting earnings from earlier quarters to later quarters of a calendar year. We have recorded pre-tax gains from the sale of interests in synthetic fuel facilities totaling $367 million, $219 million and $83 million during 2005, 2004 and 2003, respectively.

The gain from the sale of synfuel facilities is comprised of fixed and variable components. The fixed component represents note payments of principal and interest, is not subject to refund, and is recognized as a gain when earned and collectibility is assured. The variable component is based on an estimate of tax credits allocated to our partners, is subject to refund based on the annual oil price phase out, and is recognized as a gain only when the probability of refund is considered remote and collectibility is assured. In the event that the tax credit is phased-out, we are contractually obligated to refund to our partners an amount equal to all or a portion of the operating losses funded by our partners. To assess the probability of refund, we use valuation and analyst models that calculate the probability of surpassing the estimated lower band of the phase-out range for the Reference Price of oil for the year. Due to the rise in oil prices, there is a possibility that the Reference Price of oil could reach the threshold at which production tax credits begin to phase out.

Comprehensive Income

Comprehensive income is the change in common shareholders' equity during a period from transactions and events from non-owner sources, including net income. As shown in the following table, amounts recorded to other comprehensive income at December 31, 2005 include: unrealized gains and losses from derivatives accounted for as cash flow hedges, unrealized gains and losses on available for sale securities and, minimum pension liabilities .

(in Millions)	Net Unrealized Losses on Derivatives	Net Unrealized Gains on Investments	Minimum Pension Liability Adjustment	Accumulated Other Comprehensive Loss
Beginning balances	$ (100)	$ 33	$ (91)	$ (158)
Current-period change	(106)	(11)	4	(113)
Ending balance	$ (206)	$ 22	$ (87)	$ (271)

Cash Equivalents and Restricted Cash

Cash and cash equivalents include cash on hand, cash in banks and temporary investments purchased with remaining maturities of three months or less. Restricted cash consists of funds held to satisfy requirements of certain debt and partnership operating agreements. Restricted cash is classified as a current asset as all restricted cash is designated for interest and principal payments due within one year.

Inventories

We value fuel inventory and materials and supplies at average cost.

Gas inventory at MichCon is determined using the last-in, first-out (LIFO) method. At December 31, 2005, the replacement cost of gas remaining in storage exceeded the $119 million LIFO cost by $496 million. At December 31, 2004, the replacement cost of gas remaining in storage exceeded the $89 million LIFO cost by $330 million. During 2004, MichCon liquidated 5.7 billion cubic feet of prior years' LIFO layers. The liquidation benefited 2004 cost of gas by approximately $7 million, but had no impact on earnings as a result of the GCR mechanism.

Our Fuel Transportation and Marketing segment uses the average cost method for its gas in inventory.

Property, Retirement and Maintenance, and Depreciation and Depletion

Summary of property by classification as of December 31:

(in Millions)	2005	2004
Property, Plant and Equipment		
Electric Utility		
Generation	$ 7,375	$ 7,100
Distribution	6,041	5,831
Total Electric Utility	13,416	12,931
Gas Utility		
Distribution	2,098	2,020
Storage	237	221
Other	929	883
Total Gas Utility	3,264	3,124
Other Non-utility and Other	1,980	1,956
Total Property, Plant and Equipment	18,660	18,011
Less Accumulated Depreciation and Depletion		
Electric Utility		
Generation	(3,439)	(3,277)
Distribution	(2,156)	(2,077)
Total Electric Utility	(5,595)	(5,354)
Gas Utility		
Distribution	(891)	(845)
Storage	(104)	(100)
Other	(481)	(448)
Total Gas Utility	(1,476)	(1,393)
Other Non-utility and Other	(759)	(773)
Total Accumulated Depreciation and Depletion	(7,830)	(7,520)
Net Property, Plant and Equipment	$ 10,830	$ 10,491

Property is stated at cost and includes construction-related labor, materials, overheads and an allowance for funds used during construction. The cost of properties retired, less salvage, at Detroit Edison and MichCon is charged to accumulated depreciation.

Expenditures for maintenance and repairs are charged to expense when incurred, except for Fermi 2. Approximately $25 million of expenses related to the anticipated Fermi 2 refueling outage scheduled for 2006 were accrued at December 31, 2005. Amounts are being accrued on a pro-rata basis over an 18-month period that began in November 2004. We have utilized the accrue-in-advance policy for nuclear refueling outage costs since the Fermi 2 plant was placed in service in 1988. This method also matches the regulatory recovery of these costs in rates set by the MPSC.

We base depreciation provisions for utility property at Detroit Edison and MichCon on straight-line and units of production rates approved by the MPSC. The composite depreciation rate for Detroit Edison was 3.4% in 2005, 2004 and 2003. The composite depreciation rate for MichCon was 3.2%, 3.6%, and 3.5% in 2005, 2004 and 2003, respectively.

The average estimated useful life for each class of utility property, plant and equipment as of December 31, 2005 follows:

	Estimated Useful Lives in Years		
Utility	Generation	Distribution	Transmission
Electric	39	37	N/A
Gas	N/A	26	30

Non-utility property is depreciated over its estimated useful life using straight-line, declining-balance or units-of-production methods.

We credit depreciation, depletion and amortization expense when we establish regulatory assets for stranded costs related to the electric Customer Choice program and deferred environmental expenditures. We charge depreciation, depletion and amortization expense when we amortize the regulatory assets. We credit interest expense to reflect the accretion income on certain regulatory assets.

Gas Production

We follow the successful efforts method of accounting for investments in gas properties. Under this method of accounting, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending determination of whether the well has found proved reserves. If an exploratory well has not found proved reserves, the costs of drilling the well are expensed. The costs of development wells are capitalized, whether productive or nonproductive. Geological and geophysical costs on exploratory prospects and the costs of carrying and retaining unproved properties are expensed as incurred. An impairment loss is recorded to the extent that capitalized costs of unproved properties, on a property-by-property basis, are considered not to be realizable. An impairment loss is recorded if the net capitalized costs of proved gas properties exceed the aggregate related undiscounted future net revenues. Depreciation, depletion and amortization of proved gas properties are determined using the units-of-production method.

Long-Lived Assets

Our long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate the carrying amount of an asset may not be recoverable. If the carrying amount of the asset exceeds the expected future cash flows generated by the asset, an impairment loss is recognized resulting in the asset being written down to its estimated fair value. Assets to be disposed of are reported at the lower of the carrying amount or fair value less cost to sell.

Intangible Assets, Including Software Costs

Our intangible assets consist primarily of software. We capitalize the costs associated with computer software we develop or obtain for use in our business. We amortize intangible assets on a straight-line basis over the expected period of benefit, ranging from 3 to 30 years. Intangible assets amortization expense was $41 million in 2005, $43 million in 2004 and $40 million in 2003. The gross carrying amount and accumulated amortization of intangible assets at December 31, 2005 were $531 million and $167 million, respectively. The gross carrying amount and accumulated amortization of intangible assets at December 31, 2004 were $445 million and $151 million, respectively. Amortization expense of intangible assets is estimated to be $46 million annually for 2006 through 2010.

Excise and Sales Taxes

We record the billing of excise and sales taxes as a receivable with an offsetting payable to the applicable taxing authority, with no impact on the consolidated statement of operations.

Deferred Debt Costs

The costs related to the issuance of long-term debt are deferred and amortized over the life of each debt issue. In accordance with MPSC regulations applicable to our electric and gas utilities, the unamortized discount, premium and expense related to debt redeemed with a refinancing are amortized over the life of the replacement issue. Discount, premium and expense on early redemptions of debt associated with non-utility operations are charged to earnings.

Insured and Uninsured Risks

Our comprehensive insurance program provides coverage for various types of risks. Our insurance policies cover risk of loss from property damage, general liability, workers' compensation, auto liability and directors' and officers' liability. Under our risk management policy, we self-insure portions of certain risks up to specified limits, depending on the type of exposure. We have an actuarially determined estimate of our incurred but not reported liability prepared annually and adjust our reserves for self-insured risks as appropriate.

Stock-Based Compensation

We have a stock-based employee compensation plan, which is described in Note 15. The plan permits the awarding of various stock awards, including options, restricted stock and performance shares. We account for stock awards under the plan under the recognition and measurement principles of Accounting Principles Board (APB) No. 25, *Accounting for Stock Issued to Employees,* and follow the nominal vesting period approach for awards with retirement eligibility provisions. This approach differs from the non-substantive vesting period approach required by SFAS 123-R, *Share-Based Payments.* Upon adoption of SFAS 123-R, we will apply the non-substantive vesting period approach for recognizing compensation cost for all newly granted awards with retirement eligibility provisions. No compensation cost related to stock options is reflected in earnings, as all options granted had an exercise price equal to the market value of the underlying common stock on the date of grant. The recognition provisions under SFAS No. 123, *Accounting for Stock-Based Compensation*, require the recording of compensation expense for stock options equal to their fair value at date of grant as determined using an option pricing model. The following table illustrates the effect on net income and earnings per share if we had recorded compensation expense for options granted under the fair value recognition provisions of SFAS No. 123.

(in Millions, except per share amounts)	**2005**	2004	2003
Net Income as Reported	**$ 537**	$ 431	$ 521
Less: Total Stock-based Expense (1)	**(4)**	(6)	(7)
Pro Forma Net Income	**$ 533**	$ 425	$ 514
Income Per Share			
Basic — as reported	**$ 3.07**	$ 2.50	$ 3.11
Basic — pro forma	**$ 3.05**	$ 2.46	$ 3.06
Diluted — as reported	**$ 3.05**	$ 2.49	$ 3.09
Diluted — pro forma	**$ 3.03**	$ 2.45	$ 3.05

(1) Expense determined using a Black-Scholes based option pricing model.

Investments in Debt and Equity Securities

We generally classify investments in debt and equity securities as either trading or available-for-sale and have recorded such investments at market value with unrealized gains or losses included in earnings or in other comprehensive income or loss, respectively. Changes in the fair value of nuclear decommissioning-related investments are recorded as adjustments to regulatory assets or liabilities. See Note 5.

Investment in Plug Power

We own 8.8 million shares of Plug Power Inc. We account for our investment under the cost method of accounting. We record our investment at market value and account for unrealized gains and losses in other comprehensive income or loss. In December 2005, we contributed 1.8 million shares of Plug Power to the DTE Energy Foundation that resulted in a gain of approximately $1 million due to related tax effects. In May 2004, we sold 3.5 million shares of Plug Power stock and recorded a gain of approximately $14 million (net of taxes).

Consolidated Statement of Cash Flows

A detailed analysis of the changes in assets and liabilities that are reported in the consolidated statement of cash flows follows:

(in Millions)	**2005**	2004	2003
Changes in Assets and Liabilities, Exclusive of Changes Shown Separately			
Accounts receivable, net	**$ (553)**	$ 73	$ (50)
Accrued unbilled receivable	**(80)**	(62)	(20)
Accrued GCR revenue	**(16)**	(35)	29
Inventories	**(6)**	(40)	(61)
Accrued/Prepaid pensions	**17**	88	(196)
Accounts payable	**290**	266	(21)
Accrued PSCR refund	**(127)**	112	—
Exchange gas payable	**5**	(43)	90
Income taxes payable	**(38)**	(170)	135
General taxes	**(11)**	(14)	(12)
Risk management and trading activities	**353**	(64)	127
Postretirement obligation	**132**	29	112
Other assets	**52**	55	67
Other liabilities	**(129)**	(186)	(28)
	$ (111)	$ 9	$ 172

Supplementary cash and non-cash information for the years ended December 31, were as follows:

(in Millions)	**2005**	2004	2003
Cash Paid for:			
Interest (excluding interest capitalized)	**$ 516**	$ 517	$ 552
Income taxes	**$ 80**	$ 203	$ 31
Noncash Investing and Financing Activities			
Notes received from sale of synfuel projects	**$ 20**	$ 214	$ 238
Common stock contribution to pension plan	**$ —**	$ 170	$ —
Exchange of debt	**$ —**	$ —	$ 100
Sale of assets			
Note receivable	**$ 47**	$ —	$ —
Other assets	**$ 45**	$ —	$ —

We have entered into a Margin Loan Facility (Facility) with an affiliate of the clearing agent of a commodity exchange in lieu of posting additional cash collateral (a non-cash transaction). The loan outstanding under the Facility was $103 million as of December 31, 2005 and the related margin deposit is included in collateral held by others on the consolidated statement of financial position. See Note 10.

See the following notes for other accounting policies impacting our financial statements:

Note	Title
2	New Accounting Pronouncements
4	Regulatory Matters
7	Income Taxes
12	Financial and Other Derivative Instruments
14	Retirement Benefits and Trusteed Assets

NOTE 2 — NEW ACCOUNTING PRONOUNCEMENTS

Energy Trading Activities

Under Emerging Issues Task Force (EITF) Issue No. 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities*, companies were required to use mark-to-market accounting for contracts utilized in energy trading activities. EITF Issue No. 98-10 was rescinded in October 2002, and energy trading contracts must now be reviewed to determine if they meet the definition of a derivative under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*. SFAS No. 133 requires all derivatives to be recognized in the statement of financial position as either assets or liabilities measured at their fair value. SFAS No. 133 also requires that changes in the fair value of derivatives be recognized in earnings unless specific hedge accounting criteria are met. Energy trading contracts not meeting the definition of a derivative are accounted for under settlement accounting, effective October 25, 2002 for new contracts and effective January 1, 2003 for existing contracts. Derivative contracts are only marked to market to the extent that markets are considered highly liquid where objective, transparent prices can be obtained. Unrealized gains and losses are fully reserved for transactions that do not meet the criteria.

Additionally, inventory utilized in energy trading activities accounted for under the fair value method of accounting as prescribed by Accounting Research Bulletin (ARB) No. 43 is no longer permitted. Our Fuel Transportation and Marketing segment uses gas inventory in its trading operations and switched from the fair value method to the average cost method in January 2003.

Effective January 1, 2003, we no longer applied EITF Issue No. 98-10 to energy contracts and ARB No. 43 to gas inventory. As a result of discontinuing the application of these accounting principles, we recorded a cumulative effect of accounting change that reduced net income in 2003 by $16 million after-tax.

Consolidation of Variable Interest Entities

In January 2003, FIN 46, *Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin (ARB) No. 51,* was issued and requires an investor with a majority of the variable interests (primary beneficiary) in a variable interest entity to consolidate the assets, liabilities and results of operations of the entity. A variable interest entity is an entity in which the equity investors do not have controlling interests, the equity investment at risk is insufficient to finance the entity's activities without receiving additional subordinated financial support from other parties, or equity investors do not share proportionally in gains or losses.

In October 2003 and December 2003, the FASB issued Staff Position No. FIN 46-6 and FIN 46-Revised (FIN 46-R), respectively, which clarified and replaced FIN 46 and also provided for the deferral of the effective date of FIN 46 for certain variable interest entities. We have evaluated all of our equity and non-equity interests and have adopted all current provisions of FIN 46-R. The adoption of FIN 46-R did not have a material effect on our financial statements.

Medicare Act Accounting

In December 2003, the *Medicare Prescription Drug, Improvement and Modernization Act of 2003* (Medicare Act) was signed into law. The Medicare Act provides for a non-taxable federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least "actuarially equivalent" to the benefit established by law. We elected at that time to defer the provisions of the Medicare Act, and its impact on our accumulated postretirement benefit obligation and net periodic postretirement benefit cost, pending the issuance of specific authoritative accounting guidance by the FASB.

In May 2004, FASB Staff Position (FSP) No. 106-2 was issued on accounting for the effects of the Medicare Act. The guidance in this FSP is applicable to sponsors of single-employer defined benefit postretirement health care plans for which (a) the employer has concluded the prescription drug benefits available under the plan to some or all participants are "actuarially equivalent" to Medicare Part D and thus qualify for the subsidy under the Medicare Act and (b) the expected subsidy will offset or reduce the employer's share of the cost of the underlying postretirement prescription drug coverage on which the subsidy is based. We believe we qualify for the subsidy under the Medicare Act and the expected subsidy will partially offset our share of the cost of postretirement prescription drug coverage.

In June 2004, we adopted FSP No. 106-2, retroactive to January 1, 2004. As a result of the adoption, our accumulated postretirement benefit obligation for the subsidy related to benefits attributed to past service was reduced by approximately $95 million and was accounted for as an actuarial gain. The effects of the subsidy reduced net postretirement costs by $20 million in 2005 and $16 million in 2004.

Stock Based Payments

In December 2004, the FASB issued SFAS No. 123-R, *Stock Based Payments,* which established the accounting for transactions in which an entity exchanges equity instruments for goods or services. SFAS No. 123-R was effective for interim or annual periods beginning after June 15, 2005 with earlier adoption encouraged. In April 2005, the U.S. Securities and Exchange Commission delayed the effective date by requiring implementation beginning in the next fiscal year that begins after June 15, 2005. We adopted SFAS No. 123-R effective January 1, 2006. Based on historical levels of stock based payments, we estimate that the new standard will reduce net income by approximately $5 million to $10 million per year.

Asset Retirement Obligations

On January 1, 2003, we adopted SFAS No. 143, *Accounting for Asset Retirement Obligations,* which requires the fair value of an asset retirement obligation be recognized in the period in which it is incurred. We identified a legal retirement obligation for the decommissioning costs for our Fermi 1 and Fermi 2 nuclear plants. To a lesser extent, we have retirement obligations for our synthetic fuel operations, gas production facilities, asphalt plant, gas gathering facilities and various other operations.

On December 31, 2005, we adopted FASB Interpretation FIN No. 47, *Accounting for Conditional Asset Retirement Obligations*, *an interpretation of FASB Statement No. 143.* FIN 47 clarifies that the term conditional asset retirement obligation as used in FASB Statement No. 143, refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event. FIN 47 also clarifies that an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation when incurred if fair value can be reasonably estimated. The accounting for FIN 47 uses the same methodology as SFAS 143. When a new liability is recorded, an entity will capitalize the costs of the liability by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity settles the obligation for its recorded amount or incurs a gain or loss upon settlement.

As to regulated operations, we believe that adoptions of SFAS No. 143 and FIN 47 result primarily in timing differences in the recognition of legal asset retirement costs that we are currently recovering in rates. We will be deferring such differences under SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*.

As a result of adopting FIN 47 on December 31, 2005, we identified conditional retirement obligations for gas pipeline retirement costs and disposal of asbestos at certain of our power plants. To a lesser extent, we have conditional retirement obligations at certain service centers, compressor and gate stations, and PCB disposal costs within transformers and circuit breakers. We recorded a plant asset of $26 million with offsetting accumulated depreciation of $14 million, and an asset retirement obligation liability of $124 million. We also recorded a cumulative effect amount related to utility operations as a reduction to a regulatory liability of $108 million and a cumulative effect charge against earnings of $3 million, after-tax in 2005.

If we had applied FIN 47 to prior periods, we would have recorded asset retirement obligations of $123 million and $121 million as of December 31, 2004 and 2003, respectively, with an immaterial effect on earnings.

No liability has been recorded with respect to lead-based paint, as the quantities of lead-based paint are unknown. In addition, there is no incremental cost to demolitions of lead-based paint facilities vs. non-lead based paint facilities and no regulations currently exist requiring any type of special disposal of items containing lead-based paint.

Ludington Hydroelectric Power Plant has an indeterminate life and no legal obligation currently exists to decommission the plant at some future date. Substations, manholes and certain other distribution assets within Detroit Edison have an indeterminate life, therefore, no liability has been recorded for this asset.

A reconciliation of the asset retirement obligation for 2005 follows:

(in Millions)	
Asset retirement obligations at January 1, 2005	$ 916
Accretion	61
Liabilities incurred (primarily adoption of FIN 47)	129
Liabilities settled	(15)
Asset retirement obligations at December 31, 2005	$ 1,091

A significant portion of the asset retirement obligations represents nuclear decommissioning liabilities which are funded through a surcharge to electric customers over the life of the Fermi 2 nuclear plant.

NOTE 3 — DISPOSITIONS

DTE Energy Technologies (Dtech) — Discontinued Operation

We own Dtech, which assembles, markets, distributes and services distributed generation products, provides application engineering, and monitors and manages on-site generation system operations. In July 2005, management approved the restructuring of this business resulting in the identification of certain assets and liabilities to be sold or abandoned, primarily associated with standby and continuous duty operations. The systems monitoring business and certain other operations are planned to be retained. We anticipate completing the restructuring plan by mid-2006.

During the third quarter of 2005, the restructuring plan met criteria to classify the assets as “held for sale.” Accordingly, we recognized a net of tax restructuring loss of $23 million during the third quarter of 2005 primarily representing the write down to fair value of the assets of Dtech, less costs to sell, and the write-off of goodwill of $16 million. After the restructuring charge, Dtech assets are $6 million, consisting primarily of receivables and inventory, and liabilities are $6 million at December 31, 2005.

As shown in the following table, we have reported the business activity of Dtech as a discontinued operation. The amounts include the impairment loss recorded in the third quarter of 2005 and exclude general corporate overhead costs and operations that are to be retained:

(in millions)	Year Ended December 31 2005	2004	2003
Revenues(1)	**$ 18**	$ 43	**$** 36
Expenses	**67**	70	57
Loss before taxes	**(49)**	(27)	(21)
Income tax benefit	**(14)**	(9)	(7)
(Loss) from Discontinued Operations	**$ (35)**	$ (18)	**$** (14)

(1) Includes intercompany revenues of $6 million for 2005 and $5 million for 2004.

Southern Missouri Gas Company — Discontinued Operation

We owned Southern Missouri Gas Company (SMGC), a public utility engaged in the distribution, transmission and sale of natural gas in southern Missouri. In the first quarter of 2004, management approved the marketing of SMGC for sale. As of March 31, 2004, SMGC met the SFAS No. 144 criteria of an asset "held for sale" and we reported its operating results as a discontinued operation. We recognized a net of tax impairment loss in 2004 of approximately $7 million, representing the write-down to fair value of the assets of SMGC, less costs to sell, and the write-off of allocated goodwill. In November 2004, we entered into a definitive agreement providing for the sale of SMGC. Regulatory approval was received in April 2005 and the sale was closed in May 2005. During the second quarter of 2005, we recognized a net of tax gain of $2 million.

International Transmission Company — Discontinued Operation

In February 2003, we sold ITC, our electric transmission business, for $610 million to affiliates of Kohlberg Kravis Roberts & Co. and Trimaran Capital Partners, LLC. The sale generated a preliminary net of tax gain of $63 million in 2003. The gain was net of transaction costs, the portion of the gain that was refundable to customers and the write off of approximately $44 million of allocated goodwill. The gain was lowered to $58 million in 2004 under the MPSC's November 2004 final rate order that resulted in a revision of the applicable transaction costs and customer refund. During 2005, the net of tax gain was adjusted to $56 million.

We have reported the operations of ITC, from January 1, 2003 through February 28, 2003, as a discontinued operation as shown in the following table:

(in Millions)	2003
Revenues (1)	$ 21
Expenses (2)	13
Operating income	8
Income taxes	3
Income from discontinued operations	$ 5

(1) Includes intercompany revenues of $18 million.

(2) Excludes general corporate overhead costs that were previously allocated to ITC.

Detroit Edison's Steam Heating Business

In January 2003, we sold Detroit Edison's steam heating business to Thermal Ventures II, LP. Due to the continuing involvement of Detroit Edison in the steam heating business, including the commitment to purchase steam, fund certain capital improvements and guarantee the buyer's credit facility, we recorded a net of tax loss of approximately $14 million in 2003. As a result of Detroit Edison's continuing involvement, this transaction is not considered a sale for accounting purposes. See Note 13.

NOTE 4 — REGULATORY MATTERS

Regulation

Detroit Edison and MichCon are subject to the regulatory jurisdiction of the MPSC, which issues orders pertaining to rates, recovery of certain costs, including the costs of generating facilities and regulatory assets, conditions of service, accounting and operating-related matters. Detroit Edison is also regulated by the FERC with respect to financing authorization and wholesale electric activities.

As subsequently discussed in the “Electric Industry Restructuring” section, Detroit Edison’s rates were frozen through 2003 and capped for small business customers through 2004 and for residential customers through 2005 as a result of Public Act (PA) 141. However, Detroit Edison was allowed to defer certain costs to be recovered once rates could be increased, including costs incurred as a result of changes in taxes, laws and other governmental actions.

Regulatory Assets and Liabilities

Detroit Edison and MichCon apply the provisions of SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation,* to their regulated operations. SFAS No. 71 requires the recording of regulatory assets and liabilities for certain transactions that would have been treated as revenue and expense in non-regulated businesses. Continued applicability of SFAS No. 71 requires that rates be designed to recover specific costs of providing regulated services and be charged to and collected from customers. Future regulatory changes or changes in the competitive environment could result in the Company discontinuing the application of SFAS No. 71 for some or all of its utility businesses and may require the write-off of the portion of any regulatory asset or liability that was no longer probable of recovery through regulated rates. Management believes that currently available facts support the continued application of SFAS No. 71 to Detroit Edison and MichCon.

The following are balances and a brief description of the regulatory assets and liabilities at December 31:

(in Millions)	2005	2004
Assets		
Securitized regulatory assets	**$ 1,340**	$ 1,438
Recoverable income taxes related to securitized regulatory assets	**$ 734**	$ 788
Recoverable minimum pension liability	**544**	605
Asset retirement obligation	**196**	183
Other recoverable income taxes	**104**	109
Recoverable costs under PA 141		
Net stranded costs	**112**	122
Excess capital expenditures	**22**	7
Deferred Clean Air Act expenditures	**82**	76
Midwest Independent System Operator charges	**56**	27
Electric Customer Choice implementation costs	**98**	95
Enhanced security costs	**13**	8
Unamortized loss on reacquired debt	**73**	63
Deferred environmental costs	**34**	31
Accrued GCR revenue	**42**	55
Accrued PSCR revenue	**144**	—
Recoverable uncollectibles expense	**11**	—
Other	**6**	5
	2,271	2,174
Less amount included in current assets	**(197)**	(55)
	$ 2,074	$ 2,119
Liabilities		
Asset removal costs	**$ 567**	$ 679
Accrued pension	**23**	1
Refundable income taxes	**125**	135
Accrued GCR disallowance	**—**	28
Accrued PSCR refund	**129**	112
Other	**2**	4
	846	959
Less amount included in current liabilities	**(131)**	(142)
	$ 715	$ 817

ASSETS

- *Securitized regulatory assets* — The net book balance of the Fermi 2 nuclear plant was written off in 1998 and an equivalent regulatory asset was established. In 2001, the Fermi 2 regulatory asset and certain other regulatory assets were securitized pursuant to PA 142 and an MPSC order. A non-bypassable securitization bond surcharge recovers the securitized regulatory asset over a fourteen-year period ending in 2015.
- *Recoverable income taxes related to securitized regulatory assets* — Receivable for the recovery of income taxes to be paid on the non-bypassable securitization bond surcharge. A non-bypassable securitization tax surcharge recovers the income tax over a fourteen-year period ending 2015.
- *Recoverable minimum pension liability* — An additional minimum pension liability was recorded under generally accepted accounting principles due to the current under funded status of certain pension plans. The traditional rate setting process allows for the recovery of pension costs as measured by generally accepted accounting principles. Accordingly, the minimum pension liability associated with utility operations is recoverable. See Note 14.
- *Asset retirement obligation* — Asset retirement obligations were recorded pursuant to adoption of SFAS No. 143 in 2003 and FIN 47 in 2005. These obligations are primarily for Fermi 2 decommissioning costs that are recovered in rates.
- *Other recoverable income taxes* — Income taxes receivable from Detroit Edison's customers representing the difference in property-related deferred income taxes receivable and amounts previously reflected in Detroit Edison's rates.

- *Net stranded costs* — PA 141 permits, after MPSC authorization, the recovery of and a return on fixed cost deficiency associated with the electric Customer Choice program. Net stranded costs occur when fixed cost related revenues do not cover the fixed cost revenue requirements.
- *Excess capital expenditures* — Starting in 2004, PA 141 permits, after MPSC authorization, the recovery of and a return on capital expenditures that exceed a base level of depreciation expense.
- *Deferred Clean Air Act expenditures* — PA 141 permits, after MPSC authorization, the recovery of and a return on Clean Air Act expenditures.
- *Midwest Independent System Operator charges* — PA 141 permits, after MPSC authorization, the recovery of and a return on charges from a regional transmission operator such as the Midwest Independent System Operator.
- *Electric Customer Choice implementation costs* — PA 141 permits, after MPSC authorization, the recovery of and a return on costs incurred associated with the implementation of the electric Customer Choice program.
- *Enhanced security costs* — PA 609 of 2002 permits, after MPSC authorization, the recovery of enhanced security costs for an electric generating facility.
- *Unamortized loss on reacquired debt* — The unamortized discount, premium and expense related to debt redeemed with a refinancing are deferred, amortized and recovered over the life of the replacement issue.
- *Deferred environmental costs* — The MPSC approved the deferral and recovery of investigation and remediation costs associated with Gas Utility's former MGP sites.
- *Accrued GCR revenue* — Receivable for the temporary under-recovery of and a return on gas costs incurred by MichCon which are recoverable through the GCR mechanism.
- *Accrued PSCR revenue* — Receivable for the temporary under-recovery of and a return on fuel and purchased power costs incurred by Detroit Edison which are recoverable through the PSCR mechanism.
- *Recoverable uncollectibles expense* — MichCon receivable for the MPSC approved uncollectible expense true-up mechanism that tracks the difference in the fluctuation in uncollectible accounts and amounts recognized pursuant to the MPSC authorization.

LIABILITIES

- *Asset removal costs* — The amount collected from customers for the funding of future asset removal activities.
- *Accrued pension* — Pension expense refundable to customers representing the difference created from volatility in the pension obligation and amounts recognized pursuant to MPSC authorization.
- *Refundable income taxes* — Income taxes refundable to MichCon's customers representing the difference in property-related deferred income taxes payable and amounts recognized pursuant to MPSC authorization.
- *Accrued GCR disallowance* — Refund resulting from an MPSC order in MichCon's 2002 GCR plan case that required MichCon to reduce revenues in the calculation of its 2002 GCR expense.
- *Accrued PSCR refund* — Payable for the temporary over-recovery of and a return on power supply costs, and beginning with the MPSC's November 2004 rate order, transmission costs incurred by Detroit Edison which are recoverable through the PSCR mechanism.

Electric Rate Restructuring Proposal

In February 2005, Detroit Edison filed a rate restructuring proposal with the MPSC to restructure its electric rates and begin phasing out subsidies within the current pricing structure. In December 2005, the MPSC issued an order that did not provide for the comprehensive realignment of the existing rate structure that Detroit Edison requested in its rate restructuring proposal. The MPSC order did take some initial steps to improve the current competitive imbalance in Michigan's electric Customer Choice program. The December 2005 order establishes cost-based power supply rates for Detroit Edison's full service customers. Electric Customer Choice participants will pay cost-based distribution rates, while Detroit Edison's full service commercial and industrial customers will pay cost-based distribution rates that reflect the cost of the residential rate subsidy. Residential customers continue to pay a subsidized below cost rate for distribution service. These revenue neutral revised rates were effective February 1, 2006. Detroit Edison was also ordered to file a general rate case by July 1, 2007, based on 2006 actual results.

Other Postretirement Benefits Costs Tracker

In February 2005, Detroit Edison filed an application, pursuant to the MPSC's November 2004 final rate order, requesting MPSC approval of a proposed tracking mechanism for retiree health care costs. This mechanism would recognize differences between cost levels collected in rates and the actual costs under current accounting rules as regulatory assets or regulatory liabilities with an annual reconciliation proceeding before the MPSC. In February 2006, the MPSC denied Detroit Edison's request and ordered that this issue be addressed in the next general rate case due to be filed by July 1, 2007.

2004 PSCR Reconciliation and 2004 Net Stranded Cost Case

In accordance with the MPSC's direction in Detroit Edison's November 2004 rate order, in March 2005, Detroit Edison filed a joint application and testimony in its 2004 PSCR Reconciliation Case and its 2004 Net Stranded Cost Recovery Case. The combined proceeding will provide a comprehensive true-up of the 2004 PSCR and production fixed cost stranded cost calculations, including treatment of Detroit Edison's third party wholesale sales revenues. Under the MPSC's preferred methodology, Detroit Edison incurred approximately $112 million in stranded costs for 2004. Detroit Edison also received approximately $218 million in third party wholesale sales.

In the filing, Detroit Edison recommended the following distribution of the $218 million of third party wholesale sale revenues: $91 million to offset PSCR fuel expense and $74 million to offset 2004 production operation and maintenance expense. The remaining $53 million would be allocated between bundled customers and electric Customer Choice customers. This allocation would result in a refund of approximately $8 million to bundled customers and a net stranded cost amount to be collected from electric Customer Choice customers of approximately $99 million.

Included with the application was the filing of a motion for a temporary interim order requesting the continuation of the existing electric Customer Choice transition charges until a final order is issued. The MPSC denied this motion in August 2005. A final order is expected in the first half of 2006.

Electric Industry Restructuring

Electric Rates, Customer Choice and Stranded Costs — In 2000, the Michigan Legislature enacted PA 141 that reduced electric retail rates by 5%, as a result of savings derived from the issuance of securitization bonds. The legislation also contained provisions freezing rates through 2003 and preventing rate increases (i.e., rate caps) for small business customers through 2004 and for residential customers through 2005. The price freeze period expired on February 20, 2004 pursuant to an MPSC order. In addition, PA 141 codified the MPSC's existing electric Customer Choice program and provided Detroit Edison with the right to recover net stranded costs associated with electric Customer Choice. Detroit Edison was also allowed to defer certain costs to be recovered once rates could be increased, including costs incurred as a result of changes in taxes, laws and other governmental actions.

As required by PA 141, the MPSC conducted a proceeding to develop a methodology for calculating net stranded costs associated with electric Customer Choice. In a December 2001 order, the MPSC determined that Detroit Edison could recover net stranded costs associated with the fixed cost component of its electric generation operations. Specifically, there would be an annual proceeding or true-up before the MPSC reconciling the receipt of revenues associated with the fixed cost component of its generation services to the revenue requirement for the fixed cost component of those services, inclusive of an allowance for the cost of capital. Any resulting shortfall in recovery, net of mitigation, would be considered a net stranded cost. The MPSC authorized Detroit Edison to establish a regulatory asset to defer recovery of its incurred stranded costs, subject to review in a subsequent annual net stranded cost proceeding.

In July 2003, the MPSC issued an order finding that Detroit Edison had no net stranded costs in 2000 and 2001. Detroit Edison filed a petition for rehearing of the July 2003 order, which the MPSC denied in December 2003. The MPSC's November 2004 order authorized recovery of $44 million of historical stranded costs incurred in 2002, 2003 and January and February 2004 collectible from electric Customer Choice customers through transition charges. From March 2004 through the first quarter of 2005, Detroit Edison recorded $112 million of additional stranded costs as a regulatory asset as the result of rate caps and higher electric Customer Choice sales losses than included in the 2004 MPSC interim order. In March of 2005, Detroit Edison filed an application for its 2004 stranded cost recovery case. A final order is expected in the first half of 2006.

Securitization — Detroit Edison formed The Detroit Edison Securitization Funding LLC (Securitization LLC), a wholly owned subsidiary, for the purpose of securitizing its qualified costs, primarily related to the unamortized investment in the Fermi 2 nuclear power plant. In March 2001, the Securitization LLC issued $1.75 billion of securitization bonds, and Detroit Edison sold $1.75 billion of qualified costs to the Securitization LLC. The Securitization LLC is independent of Detroit Edison, as is its ownership of the qualified costs. Due to principles of consolidation, the qualified costs and securitization bonds appear on our consolidated statement of financial position. We make no claim to these assets. Ownership of such assets has vested in the Securitization LLC and been assigned to the trustee for the securitization bonds. Neither the qualified costs nor funds from an MPSC approved non-bypassable surcharge collected from Detroit Edison's customers for the payment of costs related to the Securitization LLC and securitization bonds are available to Detroit Edison's creditors.

DTE2 Accounting

In July 2004, Detroit Edison filed an accounting application with the MPSC requesting authority to capitalize and amortize DTE2 costs, consisting of computer equipment, software and development costs, as well as related training, maintenance and overhead costs. In April 2005, the MPSC approved a settlement agreement providing for the deferral of up to $60 million of certain DTE2 costs that would otherwise be expensed, as a regulatory asset for future rate recovery starting January 1, 2006. In addition, DTE2 costs recorded as plant assets will be amortized over a 15-year period.

Power Supply Recovery Proceedings

2005 Plan Year — In September 2004, Detroit Edison filed its 2005 PSCR plan case seeking approval of a levelized PSCR factor of 1.82 mills per kWh above the amount included in base rates. In December 2004, Detroit Edison filed revisions to its 2005 PSCR plan case in accordance with the November 2004 MPSC rate order. The revised filing seeks approval of a levelized PSCR factor of up to 0.48 mills per kWh above the new base rates established in the final electric rate order. Included in the factor are power supply costs, transmission expenses and nitrogen oxide emission allowance costs. Detroit Edison self-implemented a factor of negative 2.00 mills per kWh on January 1, 2005. Effective June 1, 2005, Detroit Edison began billing the maximum allowable factor of 0.48 mills per kWh due to increased power supply costs. In September 2005, the MPSC approved Detroit Edison's 2005 PSCR plan case. At December 31, 2005, Detroit Edison has recorded an under-recovery of approximately $144 million related to the 2005 plan year.

2006 Plan Year — In September 2005, Detroit Edison filed its 2006 PSCR plan case seeking approval of a levelized PSCR factor of 4.99 mills per kWh above the amount included in base rates for residential customers and 8.29 per kWh above the amount included in base rates for commercial and industrial customers. Included in the factor for all customers are power supply costs, transmission expenses, MISO market participation costs, and nitrogen oxide emission allowance costs. The Company's PSCR Plan includes a matrix which provides for different maximum PSCR factors contingent on varying electric Customer Choice sales levels. The plan also includes $97 million for recovery of its projected 2005 PSCR under-collection associated with commercial and industrial customers. Additionally, the PSCR plan requests MPSC approval of expense associated with sulfur dioxide emission allowances, mercury emission allowances, and fuel additives. In conjunction with DTE Energy's sale of the transmission assets of ITC in February 2003, the FERC froze ITC's transmission rates through December 2004. In approving the sale, FERC authorized ITC recovery of the difference between the revenue it would have collected and the actual revenue ITC did collect during the rate freeze period. At December 31, 2005 this amount is estimated to be $66 million which is to be included in ITC's rates over a five-year period beginning June 1, 2006. It is expected that this amortization will increase Detroit Edison's transmission expense in 2006 by $7 million. As previously discussed, Detroit Edison received rate orders in 2004 that allow for the recovery of transmission expenses through the PSCR mechanism.

In December 2005, the MPSC issued a temporary order authorizing the Company to begin implementation of maximum quarterly PSCR factors on January 1, 2006. The quarterly factors reflect a downward adjustment in the Company's total power supply costs of approximately 2% to reflect the potential variability in cost projections. The quarterly factors will allow the Company to more closely track the costs of providing electric service to our customers and, because the non-summer factors are well below those ordered for the summer months, effectively delay the higher power supply costs to the summer months at which time our customers will not be experiencing large expenditures for home heating. The MPSC did not adopt the Company's request to recover its projected 2005 PSCR under-collection associated with commercial and industrial customers nor did it adopt the Company's request to implement contingency factors based upon the Company's increased costs associated with providing electric service to returning electric Customer Choice customers. The MPSC deferred both of those Company proposals to the final order on the Company's entire 2006 PSCR Plan.

Administrative and General Expenses Report to the MPSC

In October 2005, the MPSC ordered Detroit Edison to file a report on why its administrative and general expenses appear to be higher than levels incurred by Consumers Energy, Michigan's other major electric utility. On February 1, 2006, a report was filed that explained Detroit Edison's administrative and general expense differences, as well as its overall cost and rate competitiveness.

Emergency Rules for Electric and Gas Bills

In October 2005, the MPSC established emergency billing practices in effect for electric and gas services rendered November 1, 2005 through March 31, 2006. These emergency rules apply to retail electric and gas customers. The rule changes:

- lengthen the period of time before a bill is due once it is transmitted to the customer;
- prohibit shut off or late payment fees unless an actual meter read is made;
- limit the required monthly payment on a settlement agreement;
- increase the income level qualifying for shut-off protection and lower the payment required to remain on shut-off protection; and
- lessen or eliminate certain deposit requirements.

Transmission Proceedings

In November 2004, a FERC order approved a transmission pricing structure to facilitate seamless trading of electricity between MISO and the PJM Interconnection. The pricing structure eliminates layers of transmission charges between the two regional transmission organizations. The FERC noted that the new pricing structure may result in transmission owners facing abrupt revenue shifts. To facilitate the transition to the new pricing structure, the FERC authorized a Seams Elimination Cost Adjustment (SECA), effective from December 2004 through March 2006. Under MISO's filing with the FERC, Detroit Edison's SECA obligation was approximately $2 million per month from December 2004 through March 2005 and approximately $1 million per month from April 2005 through March 2006. In December 2004, Detroit Edison filed a request for rehearing with the FERC which states, among other things, that SECA is retroactive ratemaking and is unlawful under the Federal Power Act. FERC has not ruled on Detroit Edison's request for rehearing. However in February 2005, FERC ordered hearings to review the proposed SECA charges. The charges are being collected subject to refund. Hearings on this matter are scheduled to conclude in late 2006. Under the MPSC's November 2004 final rate order, transmission expenses are recoverable through the PSCR mechanism. Therefore, SECA charges, if ultimately imposed, should not have a financial impact to Detroit Edison.

Gas Rate Case

On April 28, 2005, the MPSC issued an order for final rate relief. The MPSC determined that the base rate increase granted to MichCon should be $61 million annually effective April 29, 2005. This amount is an increase of $26 million over the $35 million in interim rate relief approved in September 2004. The rate increase was based on a 50% debt and 50% equity capital structure and an 11% rate of return on common equity.

The MPSC adopted MichCon's proposed tracking mechanism for uncollectible accounts receivable. Each year, MichCon will file an application comparing its actual uncollectible expense to its designated revenue recovery of approximately $37 million. Ninety percent of the difference will be refunded or surcharged after an annual reconciliation proceeding before the MPSC. The MPSC also approved the deferral of the non-capitalized portion of the negative pension expense. MichCon will record a regulatory liability for any negative pension costs as determined under generally accepted accounting principles. Included as part of the base rate increase, the order provided for $25 million in rates to recover safety and training costs. There is a one-way tracking mechanism that provides for refunding the portion of the $25 million not expended on an annual basis.

The MPSC order reduced MichCon's depreciation rates, and the related revenue requirement associated with depreciation expense by $14.5 million and is designed to have no impact on net income.

The MPSC did not allow the recovery of approximately $25 million of merger interest costs allocated to MichCon that were incurred by DTE Energy as a result of the acquisition of MCN Energy.

The MPSC order also resulted in the disallowance of computer system and equipment costs and adjustments to environmental regulatory assets and liabilities. The MPSC disallowed recovery of ninety percent of the costs of a computer billing system that was in place prior to DTE Energy's acquisition of MCN Energy in 2001. As a result of the order, MichCon recognized an impairment of this asset of approximately $42 million in the first quarter of 2005. This impairment had a minimal impact on DTE Energy because a valuation allowance was established for this asset at the time of the MCN acquisition in 2001. The MPSC disallowed approximately $6 million of certain computer equipment and related depreciation and the recovery of certain internal labor and legal costs related to remediation of MGP sites of approximately $6 million. The MPSC ordered an additional $5 million charge due to a change in the allocation of historical MGP sites insurance proceeds.

Gas Industry Restructuring

In December 2001, the MPSC approved MichCon's application for a voluntary, expanded permanent gas Customer Choice program, which replaced the experimental program that expired in March 2002. The number of customers eligible to participate in the gas Customer Choice program increased over a three-year period. Effective April 2004, all of MichCon's approximately 1.3 million customers could elect to participate in the Customer Choice program, thereby purchasing their gas from suppliers other than MichCon. The MPSC also approved the use of deferred accounting for the recovery of implementation costs of the gas Customer Choice program.

Gas Cost Recovery Proceedings

2002 Plan Year - In December 2001, the MPSC issued an order that permitted MichCon to implement GCR factors up to $3.62 per Mcf for January 2002 billings and up to $4.38 per Mcf for the remainder of 2002. The order also allowed MichCon to recognize a regulatory asset representing the difference between the $4.38 factor and the $3.62 factor for volumes that were unbilled at December 31, 2001. The regulatory asset was subject to the 2002 GCR reconciliation process. In March 2003, the MPSC issued an order in MichCon's 2002 GCR plan case. MichCon's decision during 2001 to utilize storage gas resulted in a gas inventory decrement for the 2001 calendar year. For this reason, the MPSC ordered MichCon to reduce its gas cost recovery expenses by $26.5 million for purposes of calculating the 2002 GCR factor. We recorded a $26.5 million reserve in 2003 to reflect the impact of this order.

MichCon's 2002 GCR reconciliation case was filed with the MPSC in February 2003. The Staff and various intervening parties in this proceeding sought to have the MPSC disallow an additional $26 million, representing unbilled revenues at December 2001. One party also proposed the disallowance of half of an $8 million payment made to settle Enron bankruptcy issues. The other parties to the case recommended that the Enron bankruptcy settlement be addressed in the 2003 GCR reconciliation case. In April 2005, the MPSC issued an order in the 2002 GCR reconciliation case affirming the order in the 2002 GCR plan case disallowing $26.5 million related to the use of storage gas in 2001. The April 2005 order also disallowed the additional $26 million representing unbilled revenues at December 2001. We recorded the impact of the disallowance in the first quarter of 2005. The MPSC agreed that the $8 million related to the Enron issue be addressed in the 2003 GCR reconciliation case.

2003 Plan Year - MichCon's 2003 GCR reconciliation case was filed with the MPSC in February 2004. In May 2005, the MPSC issued an order in the 2003 GCR reconciliation case approving recovery of the $8 million related to the Enron bankruptcy settlement.

2004 Plan Year — In September 2003, MichCon filed its 2004 GCR plan case proposing a maximum GCR factor of $5.36 per Mcf. MichCon agreed to switch from a calendar year to an operational year as a condition of its settlement in the 2003 GCR plan case. The operational GCR year runs from April to March of the following year. To accomplish the switch, the 2004 GCR plan reflected a 15-month transitional period, January 2004 through March 2005. Under this transition proposal, MichCon filed two reconciliations pertaining to the transition period; one in June 2004 addressing January through March 2004, one filed in June 2005 addressing the remaining April 2004 through March 2005 period and consolidating the two for purposes of the case. The June 2005 filing supported the $46 million under-recovery with interest MichCon had accrued for the period ending March 31, 2005. MichCon does not expect a final order before the third quarter of 2006.

2005-2006 Plan Year — In December 2004, MichCon filed its 2005-2006 GCR plan case proposing a maximum GCR factor of $7.99 per Mcf. The plan includes quarterly contingent GCR factors. These contingent factors allow MichCon to increase the maximum GCR factor to compensate for increases in gas market prices, thereby reducing the possibility of a GCR under-recovery. In April 2005, the MPSC issued an order recognizing that Michigan law allows MichCon to self-implement its quarterly contingent factors. MichCon self-implemented quarterly contingent GCR factors of $8.54 per Mcf in July 2005 and $10.09 per Mcf in October 2005.

In response to market price increases in the fall of 2005, MichCon filed a petition to reopen the record in the case during September 2005. MichCon proposed a revised maximum GCR factor of $13.10 per Mcf and a revised contingent factor matrix. In its order issued October 6, 2005, the MPSC reopened the record in the case. On October 28, 2005, the MPSC approved an increase in the GCR factor to a cap of $11.3851 per Mcf for the period November 2005 through March 2006.

2006-2007 Plan Year — In December 2005, MichCon filed its 2006-2007 GCR plan case proposing a maximum GCR Factor of $12.15 per Mcf. The plan includes quarterly contingent GCR factors. These contingent factors allow MichCon to increase the maximum GCR factor to compensate for increases in market prices, thereby reducing the possibility of a GCR under-recovery.

Minimum Pension Liability

In December 2002, we recorded an additional minimum pension liability as required under SFAS No. 87, with offsetting amounts to an intangible asset and other comprehensive income. During 2003, the MPSC Staff provided an opinion that the MPSC's traditional rate setting process allowed for the recovery of pension costs as measured by SFAS No. 87. Based on the MPSC Staff opinion, management believes that it will be allowed to recover in rates the minimum pension liability associated with its utility operations and as such the amount was reclassified to a regulatory asset. At December 31, 2005 and 2004, we have recorded a regulatory asset of approximately $544 million ($354 million net of tax) and $605 million ($393 million net of tax), respectively. See Note 14.

Other

We are unable to predict the outcome of the regulatory matters discussed herein. Resolution of these matters is dependent upon future MPSC orders and appeals, which may materially impact the financial position, results of operations and cash flows of the Company.

NOTE 5 — NUCLEAR OPERATIONS

General

Fermi 2, our nuclear generating plant, began commercial operation in 1988. Fermi 2 has a design electrical rating (net) of 1,150 megawatts. This plant represents approximately 10% of Detroit Edison's summer net rated capability. The net book balance of the Fermi 2 plant was written off at December 31, 1998, and an equivalent regulatory asset was established. In 2001, the Fermi 2 regulatory asset was securitized. See Note 4. Detroit Edison also owns Fermi 1, a nuclear plant that was shut down in 1972 and is currently being decommissioned. The NRC has jurisdiction over the licensing and operation of Fermi 2 and the decommissioning of Fermi 1.

Property Insurance

Detroit Edison maintains several different types of property insurance policies specifically for the Fermi 2 plant. These policies cover such items as replacement power and property damage. The Nuclear Electric Insurance Limited (NEIL) is the primary supplier of the insurance polices.

Detroit Edison maintains a policy for extra expenses, including replacement power costs necessitated by Fermi 2's unavailability due to an insured event. These policies have a 12-week waiting period and provide an aggregate $490 million of coverage over a three-year period.

Detroit Edison has $500 million in primary coverage and $2.25 billion of excess coverage for stabilization, decontamination, debris removal, repair and/or replacement of property and decommissioning. The combined coverage limit for total property damage is $2.75 billion.

For multiple terrorism losses caused by acts of terrorism not covered under the Terrorism Risk Insurance Extension Act of 2005 (TRIA) occurring within one year after the first loss from terrorism, the NEIL policies would make available to all insured entities up to $3.2 billion, plus any amounts recovered from reinsurance, government indemnity, or other sources to cover losses.

Under the NEIL policies, Detroit Edison could be liable for maximum assessments of up to approximately $30 million per event if the loss associated with any one event at any nuclear plant in the United States should exceed the accumulated funds available to NEIL.

Public Liability Insurance

As required by federal law, Detroit Edison maintains $300 million of public liability insurance for a nuclear incident. For liabilities arising from a terrorist act outside the scope of TRIA, the policy is subject to one industry aggregate limit of $300 million. Further, under the Price-Anderson Amendments Act of 2005, deferred premium charges up to $101 million could be levied against each licensed nuclear facility, but not more than $15 million per year per facility. Thus, deferred premium charges could be levied against all owners of licensed nuclear facilities in the event of a nuclear incident at any of these facilities.

Decommissioning

Detroit Edison has a legal obligation to decommission its nuclear power plants following the expiration of their operating licenses. This obligation is reflected as an asset retirement obligation, which is classified as a noncurrent regulatory liability. Based on the actual or anticipated extended life of the nuclear plant, decommissioning expenditures for Fermi 2 are expected to be incurred primarily during the period 2025 through 2041. It is estimated that the cost of decommissioning Fermi 2, when its license expires in 2025, will be $1.1 billion in 2005 dollars and $3.4 billion in 2025 dollars, using a 6% inflation rate. In 2001, Detroit Edison began the decommissioning of Fermi 1, with the goal of removing the radioactive material and terminating the Fermi 1 license. The decommissioning of Fermi 1 is expected to be complete by 2010.

Detroit Edison currently recovers funds for decommissioning and the disposal of low-level radioactive waste through a revenue surcharge. The amounts recovered from customers are deposited in the restricted external trust accounts to fund decommissioning.

(in Millions)	2005	2004	2003
Revenue	$ 40	$ 38	$ 36
Net unrealized investment gains	—	17	62

The nuclear decommissioning cost will be funded by investments held in trust funds that have been established for each nuclear station. Nuclear decommissioning trust funds are as follows:

	As of December 31	
(in Millions)	2005	2004
Fermi 2	$ 601	$ 546
Fermi 1	18	18
Low level radioactive waste	27	26
Total	$ 646	$ 590

At December 31, 2005, investments in the external trust consisted of approximately 49% in publicly traded equity securities, 44% in fixed debt instruments and 7% in cash equivalents.

The NRC has jurisdiction over the decommissioning of nuclear power plants and requires decommissioning funding based upon a formula. The MPSC and FERC regulate the recovery of costs of decommissioning nuclear power plants and both require the use of external trust funds to finance the decommissioning of Fermi 2. Rates approved by the MPSC provide for the recovery of decommissioning costs of Fermi 2. Detroit Edison is continuing to fund FERC jurisdictional amounts for decommissioning even though explicit provisions are not included in FERC rates. We believe the MPSC and FERC collections will be adequate to fund the estimated cost of decommissioning using the NRC formula. The decommissioning assets, anticipated earnings thereon and future revenues from decommissioning collections will be used to decommission the nuclear facilities. We expect the regulatory liabilities to be reduced to zero at the conclusion of the decommissioning activities. If amounts remain in the trust funds for these units following the completion of the decommissioning activities, those amounts will be returned to the ratepayers.

Nuclear Fuel Disposal Costs

In accordance with the Federal Nuclear Waste Policy Act of 1982, Detroit Edison has a contract with the U.S. Department of Energy (DOE) for the future storage and disposal of spent nuclear fuel from Fermi 2. Detroit Edison is obligated to pay the DOE a fee of 1 mill per kWh of Fermi 2 electricity generated and sold. The fee is a component of nuclear fuel expense. Delays have occurred in the DOE's program for the acceptance and disposal of spent nuclear fuel at a permanent repository. Until the DOE is able to fulfill its obligation under the contract, Detroit Edison is responsible for the spent nuclear fuel storage. Detroit Edison estimates that existing storage capacity will be sufficient until 2007. We plan expansion of our spent fuel storage capacity that will meet our requirements through 2010. Detroit Edison is a party in the litigation against the DOE for both past and future costs associated with the DOE's failure to accept spent nuclear fuel under the timetable set forth in the Federal Nuclear Waste Policy Act of 1982.

NOTE 6 — JOINTLY OWNED UTILITY PLANT

Detroit Edison has joint ownership interest in two power plants, Belle River and Ludington Hydroelectric Pumped Storage. Ownership information of the two utility plants as of December 31, 2005 was as follows:

	Belle River	Ludington Hydroelectric Pumped Storage
In-service date	1984-1985	1973
Total plant capacity	1,026 MW	1,872 MW
Ownership interest	*	49%
Investment (in Millions)	$ 1,571	$ 167
Accumulated depreciation (in Millions)	$ 778	$ 92

* Detroit Edison's ownership interest is 63% in Unit No. 1, 81% of the facilities applicable to Belle River used jointly by the Belle River and St. Clair Power Plants and 75% in common facilities used at Unit No. 2.

Belle River

The Michigan Public Power Agency (MPPA) has an ownership interest in Belle River Unit No. 1 and other related facilities. The MPPA is entitled to 19% of the total capacity and energy of the plant and is responsible for the same percentage of the plant's operation, maintenance and capital improvement costs.

Ludington Hydroelectric Pumped Storage

Consumers Energy Company has an ownership interest in the Ludington Hydroelectric Pumped Storage Plant. Consumers Energy is entitled to 51% of the total capacity and energy of the plant and is responsible for the same percentage of the plant's operation, maintenance and capital improvement costs.

NOTE 7 — INCOME TAXES

We file a consolidated federal income tax return.

Total income tax expense (benefit) varied from the statutory federal income tax rate for the following reasons:

(Dollars in Millions)	**2005**	2004	2003
Income before income taxes and minority interest	**$ 497**	$ 423	$ 287
Less minority interest	**(281)**	(212)	(91)
Income from continuing operations before tax	**$ 778**	$ 635	$ 378
Income tax expense at 35% statutory rate	**$ 272**	$ 222	$ 132
Production tax credits	**(55)**	(38)	(241)
Investment tax credits	**(8)**	(8)	(8)
Depreciation	**(4)**	(4)	(4)
Employee Stock Ownership Plan dividends	**(5)**	(5)	(5)
Medicare part D exempt income	**(7)**	(5)	—
Other, net	**9**	12	10
Income tax expense (benefit) from continuing operations	**$ 202**	$ 174	$ (116)
Effective federal income tax rate	**25.9%**	27.4%	(30.7)%

The minority interest allocation reflects the adjustment to earnings to allocate partnership losses to third party owners. The tax impact of partnership earnings and losses are attributable to the partners instead of the partnerships. The minority interest allocation is therefore removed in computing income taxes associated with continuing operations.

Components of income tax expense (benefit) were as follows:

(in Millions)	**2005**	2004	2003
Continuing Operations			
Current federal and other income tax expense	**$ 57**	$ 40	$ 21
Deferred federal income tax expense (benefit)	**145**	134	(137)
	202	174	(116)
Discontinued operations	**(13)**	(13)	54
Cumulative Effect of Accounting Changes	**(2)**	—	(15)
Total	**$ 187**	$ 161	$ (77)

Production tax credits are provided for qualified fuels produced and sold by a taxpayer to an unrelated party during the taxable year. Production tax credits earned but not utilized totaled $484 million and are carried forward indefinitely as alternative minimum tax credits. The majority of the production tax credits earned, including all of those from our synfuel projects, were generated from projects that have received a private letter ruling (PLR) from the Internal Revenue Service (IRS). These PLRs provide assurance as to the appropriateness of using these credits to offset taxable income, however, these tax credits are subject to IRS audit and adjustment.

We have a net operating loss carry-forward of $160 million that expires in years 2019 through 2020. We do not believe that a valuation allowance is required, as we expect to utilize the loss carry-forward prior to its expiration.

Deferred tax assets and liabilities are recognized for the estimated future tax effect of temporary differences between the tax basis of assets or liabilities and the reported amounts in the financial statements. Deferred tax assets and liabilities are classified as current or noncurrent according to the classification of the related assets or liabilities. Deferred tax assets and liabilities not related to assets or liabilities are classified according to the expected reversal date of the temporary differences.

Deferred tax assets (liabilities) were comprised of the following at December 31:

(in Millions)	**2005**	2004
Property	**$ (1,234)**	$ (1,193)
Securitized regulatory assets	**(723)**	(778)
Alternative minimum tax credit carryforward	**484**	483
Merger basis differences	**115**	125
Pension and benefits	**15**	(56)
Net operating loss	**56**	71
Other	**148**	317
	$ (1,139)	$ (1,031)
Deferred income tax liabilities	**$ (2,635)**	$ (2,527)
Deferred income tax assets	**1,496**	1,496
	$ (1,139)	$ (1,031)

The above table excludes deferred tax liabilities associated with unamortized investment tax credits which are shown separately on the consolidated statement of financial position.

During 2005, the IRS completed and closed its audits of our federal income tax returns for the years 1998 through 2001. The IRS is currently conducting audits of our federal income tax returns for the years 2002 and 2003. The Company accrues tax and interest related to tax uncertainties that arise due to actual or potential disagreements with governmental agencies about the tax treatment of specific items. At December 31, 2005, the Company had accrued approximately $38 million for such uncertainties. We believe that our accrued tax liabilities are adequate for all years.

NOTE 8 — COMMON STOCK AND EARNINGS PER SHARE

Common Stock

In August 2005, we successfully remarketed the senior notes comprising part of our Equity Security Units that were issued in June 2002. We also settled the stock purchase contract component of the Equity Security Units by issuing 3.7 million shares of common stock to holders of these units in August 2005 at an issue price of $46.79. The issue price was calculated by using the average closing price per share of our common stock during a 20 trading-day period ending August 11, 2005.

In March 2004, we issued 4,344,492 shares of DTE Energy common stock, valued at $170 million. The common stock was contributed to a defined benefit retirement plan.

Under the DTE Energy Company Long-Term Incentive Plan, we grant non-vested stock awards to key employees, primarily management. At the time of grant, we record the fair value of the non-vested awards as unearned compensation, which is reflected as a reduction in common stock. The number of non-vested stock awards is included in the number of common shares outstanding; however, for purposes of computing basic earnings per share, non-vested stock awards are excluded.

Shareholders' Rights Agreement

We have a Shareholders' Rights Agreement designed to maximize shareholder value should DTE Energy be acquired. Under certain triggering events, each right entitles the holder to purchase from DTE Energy one one-hundredth of a share of Series A Junior Participating Preferred Stock of DTE Energy at a price of $90, subject to adjustment as provided for in the Shareholders' Rights Agreement. The rights expire in October 2007.

Earnings per Share

We report both basic and diluted earnings per share. Basic earnings per share is computed by dividing income from continuing operations by the weighted average number of common shares outstanding during the period. Diluted earnings per share assumes the issuance of potentially dilutive common shares outstanding during the period and the repurchase of common shares that would have occurred with proceeds from the assumed issuance. Diluted earnings per share assume the exercise of stock options, vesting of non-vested stock awards, and the issuance of performance share awards. A reconciliation of both calculations is presented in the following table:

(in Millions, except per share amounts)	**2005**	2004	2003
Basic Earnings per Share			
Income from continuing operations	**$ 576.5**	$ 460.5	$ 494.0
Average number of common shares outstanding	**175.0**	172.6	167.7
Income per share of common stock based on average number of shares outstanding	**$ 3.29**	$ 2.67	$ 2.95
Diluted Earnings per Share			
Income from continuing operations	**$ 576.5**	$ 460.5	$ 494.0
Average number of common shares outstanding	**175.0**	172.6	167.7
Incremental shares from stock-based awards	**1.1**	.7	.6
Average number of dilutive shares outstanding	**176.1**	173.3	168.3
Income per share of common stock assuming issuance of incremental shares	**$ 3.27**	**$** 2.66	**$** 2.93

Options to purchase approximately two million shares of common stock in 2005, one million shares in 2004 and five million shares in 2003 were not included in the computation of diluted earnings per share because the options' exercise price was greater than the average market price of the common shares, thus making these options anti-dilutive.

NOTE 9 — LONG-TERM DEBT AND PREFERRED SECURITIES

Long-Term Debt

Our long-term debt outstanding and weighted average interest rates of debt outstanding at December 31 were:

(in Millions)	2005 (1)	2004
DTE Energy Debt, Unsecured		
6.7% due 2006 to 2033	**$ 1,696**	$ 1,945
Detroit Edison Taxable Debt, Principally Secured		
5.8% due 2010 to 2037	**2,030**	1,672
Detroit Edison Tax Exempt Revenue Bonds (2)		
5.3% due 2008 to 2032	**1,145**	1,145
MichCon Taxable Debt, Principally Secured		
6.2% due 2006 to 2033	**785**	785
Quarterly Income Debt Securities (QUIDS)	**—**	385
Other Long-Term Debt, Including Non-Recourse Debt	**155**	151
	5,811	6,083
Less amount due within one year	**(577)**	(410)
	$ 5,234	$ 5,673
Securitization Bonds	**$ 1,400**	$ 1,496
Less amount due within one year	**(105)**	(96)
	$ 1,295	$ 1,400
Equity-Linked Securities	**$ 175**	$ 178
Trust Preferred — Linked Securities		
7.8% due 2032	**$ 186**	$ 186
7.5% due 2044	**103**	103
	$ 289	$ 289

(1) Weighted average interest rates as of December 31, 2005

(2) Detroit Edison Tax Exempt Revenue Bonds are issued by a public body that loans the proceeds to Detroit Edison on terms substantially mirroring the Revenue Bonds

Debt Issuances

In 2005, we issued the following long-term debt:

Company	Month Issued	Type	Interest Rate	Maturity	(in Millions) Amount
Detroit Edison	February	Senior Notes (1)	4.80%	February 2015	$ 200
Detroit Edison	February	Senior Notes (1)	5.45%	February 2035	200
Detroit Edison	August	Tax Exempt Revenue Bonds (2)	variable	August 2029	119
DTE PetCoke	September	Taxable Bonds	variable	January 2025	10
Detroit Edison	September	Senior Notes (3)	5.19%	October 2023	100
Detroit Edison	October	Senior Notes (4)	5.70%	October 2037	250
				Total Issuances	**$ 879**

(1) The proceeds from the issuance were used to redeem QUIDS of Detroit Edison

(2) The proceeds from the issuance were used to refinance Tax Exempt Revenue Bonds of Detroit Edison

(3) The proceeds from the issuance were used to redeem Senior Notes of Detroit Edison

(4) The proceeds from the issuance were used to repay short term borrowings of Detroit Edison

We acquired $15 million in various notes in connection with acquisitions during 2005.

Debt Retirements and Redemptions

The following debt was retired, through optional redemption or payment at maturity, during 2005.

Company	Month Retired	Type	Interest Rate	Maturity	(in Millions) Amount
Detroit Edison	February	Senior Notes	7.500%	February 2005	$ 76
Detroit Edison	February	Remarketed Senior Notes	7.000%	August 2034	100
Detroit Edison	March	QUIDS (1)	7.625%	March 2026	185
Detroit Edison	March	QUIDS (1)	7.540%	June 2028	100
Detroit Edison	March	QUIDS (1)	7.375%	December 2028	100
Detroit Edison	September	Tax Exempt Revenue Bond (2)	6.400%	September 2025	97
Detroit Edison	September	Tax Exempt Revenue Bond (2)	6.200%	August 2025	22
DTE Energy	September	Senior Notes	Variable	June 2007	250
Detroit Edison	October	Senior Notes (3)	5.050%	October 2005	200
			Total Retirements		**$ 1,130**

(1) The QUIDS were redeemed with the proceeds from issuance of Senior Notes by Detroit Edison

(2) These Tax Exempt Revenue Bonds were redeemed with the proceeds from issuance of new Detroit Edison Tax Exempt Revenue Bonds

(3) These Senior Notes were paid at maturity with the proceeds from the issuance of Senior Notes by Detroit Edison and short-term borrowings

The following table shows the scheduled debt maturities, excluding any unamortized discount or premium on debt:

(in millions)	2006	2007	2008	2009	2010	2011 and thereafter	Total
Amount to mature	$ 682	$ 352	$ 457	$ 363	$ 681	$ 5,150	**$ 7,685**

Remarketable Securities

At December 31, 2004, $175 million of notes of Detroit Edison and MichCon were subject to periodic remarketings. The $100 million scheduled to remarket in February 2005 was optionally redeemed by Detroit Edison, and we do not expect any remarketings to take place in 2006. We direct the remarketing agents to remarket these securities at the lowest interest rate necessary to produce a par bid. In the event that a remarketing fails, we would be required to purchase the securities.

Quarterly Income Debt Securities (QUIDS)

Detroit Edison had three series of QUIDS outstanding at December 31, 2004. Detroit Edison redeemed all of its outstanding QUIDS on March 4, 2005.

Equity-Linked Securities

In June 2002, DTE Energy issued $173 million of 8.75% Equity Security Units, with each unit consisting of a stock purchase contract and a senior note of DTE Energy. In August 2005, DTE Energy successfully remarketed $172 million aggregate principal amount of its 5.63% Senior Notes due August 16, 2007 that were originally issued as a component of the 8.75% Equity Security Units. Additionally, in August 2005, DTE Energy settled the stock purchase contract component of its Equity Security Units by issuing common stock to holders of these units. The issue price determined by the average closing price per share of our common stock during a 20 trading-day period ending August 11, 2005 was $46.79 per share. Settlement of the purchase contracts resulted in DTE Energy issuing approximately 3.7 million shares of common stock in exchange for approximately $172 million.

Trust Preferred-Linked Securities

DTE Energy has interests in various unconsolidated trusts that were formed for the sole purpose of issuing preferred securities and lending the gross proceeds to us. The sole assets of the trusts are debt securities of DTE Energy with terms similar to those of the related preferred securities. Payments we make are used by the trusts to make cash distributions on the preferred securities it has issued.

We have the right to extend interest payment periods on the debt securities. Should we exercise this right, we cannot declare or pay dividends on, or redeem, purchase or acquire, any of our capital stock during the deferral period.

DTE Energy has issued certain guarantees with respect to payments on the preferred securities. These guarantees, when taken together with our obligations under the debt securities and related indenture, provide full and unconditional guarantees of the trusts' obligations under the preferred securities.

Financing costs for these issuances were paid for and deferred by DTE Energy. These costs are being amortized using the straight-line method over the estimated lives of the related securities.

Cross Default Provisions

Substantially all of the net utility properties of Detroit Edison and MichCon are subject to the lien of mortgages. Should Detroit Edison or MichCon fail to timely pay their indebtedness under these mortgages, such failure may create cross defaults in the indebtedness of DTE Energy.

Preferred and Preference Securities – Authorized and Unissued

As of December 31, 2005, the amount of authorized and unissued stock is as follows:

Company	Type of Stock	Par Value	Shares Authorized
DTE Energy	Preferred (1)	None	5,000,000
Detroit Edison	Preferred	$ 100	6,750,000
Detroit Edison	Preference	$ 1	30,000,000
MichCon	Preferred	$ 1	7,000,000
MichCon	Preference	$ 1	4,000,000

(1) 1.5 million shares are reserved for issuance under the Shareholder's Rights Agreement

NOTE 10 — SHORT-TERM CREDIT ARRANGEMENTS AND BORROWINGS

DTE Energy and its wholly-owned subsidiaries, Detroit Edison and MichCon, have entered into revolving credit facilities with similar terms. The five-year credit facilities are with a syndicate of banks and may be used for general corporate borrowings, but are intended to provide liquidity support for each of the Companies' commercial paper programs.

In October 2005, DTE Energy, Detroit Edison and MichCon entered into new five-year revolving credit agreements with an aggregate capacity of $925 million. Simultaneously, we amended our existing $975 million, five-year revolving credit facilities to provide for the substitution of some of the participating lenders, as well as modifications to pricing, conditions to borrowing, covenants, events of default and other miscellaneous provisions to conform to the terms of the new agreements. The aggregate availability under these combined facilities is $1.9 billion as shown in the following table:

(in Millions)	DTE Energy	Detroit Edison	MichCon	Total
Five-year unsecured revolving facility, dated October 2005	$ 675	$ 69	$ 181	$ 925
Five-year unsecured revolving facility, dated October 2004	525	206	244	975
Aggregate availability	$ 1,200	$ 275	$ 425	$ 1,900

Borrowings under the facilities are available at prevailing short-term interest rates. The agreements require each of the companies to maintain a debt to total capitalization ratio of no more than .65 to l. Should either Detroit Edison or MichCon have delinquent debt obligations of at least $50 million to any creditor, such delinquency will be considered a default under DTE Energy's credit agreements. DTE Energy, Detroit Edison and MichCon are currently in compliance with these financial covenants. As of December 31, 2005, we had outstanding commercial paper of $841 million. In addition, we had approximately $284 million of letters of credit outstanding against these facilities at December 31, 2005.

In December 2005, DTE Energy entered into a new $150 million letter of credit and reimbursement agreement. The reimbursement agreement has a one-year term with a variable interest rate. Provisions for an automatic one-year extension and conversion to a two-year term loan are available as long as certain conditions are met. We had approximately $80 million of letters of credit outstanding against this agreement at December 31, 2005.

In conjunction with maintaining certain exchange traded risk management positions, we may be required to post cash collateral with our clearing agent. We have entered into a Margin Loan Facility (Facility) with an affiliate of the clearing agent of up to $103 million as of December 31, 2005. We entered into this facility in lieu of posting cash. This facility was backed by a letter of credit issued by DTE Energy in the amount of $100 million. Any margin requirement in excess of the Facility is funded in cash by DTE Energy. The amount outstanding under the Facility is subject to an interest rate at a per annum rate of interest equal to the LIBOR rate, plus 0.75%, calculated daily. The amount outstanding under the Facility was $103 million and $23 million as of December 31, 2005 and 2004, respectively.

Detroit Edison has a $200 million short-term financing agreement secured by customer accounts receivable. This agreement contains certain covenants related to the delinquency of accounts receivable. Detroit Edison is currently in compliance with these covenants. We had no balances outstanding under this financing agreement at December 31, 2005 and 2004.

The weighted average interest rates for short-term borrowings were 4.4% and 2.4% at December 31, 2005 and 2004, respectively.

NOTE 11 – CAPITAL AND OPERATING LEASES

Lessee – We lease various assets under capital and operating leases, including coal cars, a gas storage field, office buildings, a warehouse, computers, vehicles and other equipment. The lease arrangements expire at various dates through 2029.

Future minimum lease payments under non-cancelable leases at December 31, 2005 were:

(in Millions)	Capital Leases	Operating Leases
2006	$ 16	$ 63
2007	13	51
2008	15	42
2009	15	35
2010	13	29
Thereafter	52	316
Total minimum lease payments	124	$ 536
Less imputed interest	(26)	
Present value of net minimum lease payments	98	
Less current portion	(11)	
Non-current portion	$ 87	

Rental expense for operating leases was $77 million in 2005, $75 million in 2004 and $73 million in 2003.

Lessor – MichCon leases a portion of its pipeline system to the Vector Pipeline Partnership through a capital lease contract that expires in 2020, with renewal options extending for five years. The components of the net investment in the capital lease at December 31, 2005, were as follows:

(in Millions)	
2006	$ 9
2007	9
2008	9
2009	9
2010	9
Thereafter	89
Total minimum future lease receipts	134
Residual value of leased pipeline	40
Less unearned income	(93)
Net investment in capital lease	81
Less current portion	(1)
	$ 80

NOTE 12 – FINANCIAL AND OTHER DERIVATIVE INSTRUMENTS

We comply with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* , as amended by SFAS No. 138 and SFAS No. 149. Listed below are important SFAS No. 133 requirements:

- Derivative instruments must be recognized as assets or liabilities and measured at fair value, unless they meet the normal purchases and sales exemption.
- Accounting for changes in fair value depends on the purpose of the derivative instrument and whether it is designated as a hedge and qualifies for hedge accounting.
- Special accounting is allowed for a derivative instrument qualifying as a hedge and designated as a hedge for the variability of cash flow associated with a forecasted transaction. Gain or loss associated with the

effective portion of the hedge is recorded in other comprehensive income. The ineffective portion is recorded to earnings. Amounts recorded in other comprehensive income will be reclassified to net income when the forecasted transaction affects earnings. If a cash flow hedge is discontinued because it is likely the forecasted transaction will not occur, net gains or losses are immediately recorded to earnings.

- Special accounting is allowed for derivative instruments that qualifying as a hedge and designated as a hedge of the changes in fair value of an existing asset, liability or firm commitment. Gain or loss on the hedging instrument is recorded into earnings. An offsetting loss or gain on the underlying asset, liability or firm commitment is also recorded to earnings.

Our primary market risk exposure is associated with commodity prices, credit, interest rates and foreign currency. We have risk management policies to monitor and decrease market risks. We use derivative instruments to manage some of the exposure. Except for the activities of the Fuel Transportation and Marketing segment, we do not hold or issue derivative instruments for trading purposes. The fair value of all derivatives is shown as "assets or liabilities from risk management and trading activities" in the consolidated statement of financial position.

Commodity Price Risk

Utility Operations

Detroit Edison – Detroit Edison generates, purchases, distributes and sells electricity. Detroit Edison uses forward energy, capacity, and futures contracts to manage changes in the price of electricity and fuel. These derivatives are designated as cash flow hedges or meet the normal purchases and sales exemption and are therefore accounted for under the accrual method. There were no commodity price risk cash flow hedges for utility operations at December 31, 2005.

MichCon – MichCon purchases, stores, transmits and distributes and sells natural gas. MichCon has fixed-priced contracts for portions of its expected gas supply requirements through 2008. These gas supply and firm transportation contracts are designated and qualify for the normal purchases and sales exemption and are therefore accounted for under the accrual method.

Commodity price risk associated with our utilities is limited due to the PSCR and GCR mechanisms. See Note 1.

Non-Utility Operations

Fuel Transportation and Marketing – DTE Energy Trading markets and trades wholesale electricity and natural gas physical products, trades financial instruments, and provides risk management services utilizing energy commodity derivative instruments. Forwards, futures, options and swap agreements are used to manage exposure to the risk of market price and volume fluctuations on its operations. These derivatives are accounted for by recording changes in fair value to earnings, usually as adjustments to operating revenues or fuel, purchased power and gas expense. This fair value accounting better aligns financial reporting with the way the business is managed and its performance measured.

Fuel Transportation and Marketing experiences earnings volatility as a result of its gas inventory and other non-derivative assets that do not qualify for fair value accounting under accounting principles generally accepted in the U.S. Although the risks associated with these asset positions are substantially offset, requirements to fair value the underlying derivatives result in unrealized gains and losses being recorded to earnings that eventually reverse upon settlement.

Power and Industrial Projects – The Coal-Based Fuels and Landfill Gas Recovery businesses generate production tax credits. We have sold interests in all nine of our synthetic fuel production plants. Proceeds from the sales are contingent upon production levels, the production qualifying for production tax credits, and the value of such credits. Production tax credits are subject to phase out if domestic crude oil prices reach certain levels. See Note 13.

To manage our exposure in 2006 and 2007 to the risk of an increase in oil prices that could reduce or eliminate synfuel sales proceeds, we entered into a series of derivative contracts covering a specified number of barrels of oil. The derivative contracts involve purchased and written call options that provide for net cash settlement at expiration based on the full years' 2006 and 2007 average New York Mercantile Exchange (NYMEX) trading prices for light, sweet crude oil in relation to the strike prices of each option. If the average NYMEX prices of oil in 2006 and 2007 are less than approximately $58, and $60, per barrel, respectively, the derivatives will yield no payment. If the average NYMEX prices of oil exceed approximately $58, and $60, per barrel, respectively, the derivatives will yield a payment equal to the excess of the average NYMEX price over these initial strike prices, multiplied by the number of barrels covered, up to a maximum price of approximately $73, and $71 per barrel, respectively. The agreements do not qualify for hedge accounting. Consequently, changes in the fair value of the options are recorded currently in earnings. For all synfuel hedge contracts, including 2005 hedges, we recorded total pretax mark to market gains of $48 million in 2005. The fair value changes are recorded as adjustments to the gain from selling interests in synfuel facilities and therefore included in the "Asset gains and losses, net" line item in the consolidated statement of operations.

Unconventional Gas Production – Our Unconventional Gas business is engaged in natural gas exploration, development and production. We use derivative contracts to manage changes in the price of natural gas. These derivatives are designated as cash flow hedges and are primarily legacy transactions. Amounts recorded in other comprehensive loss will be reclassified to earnings as the related production affects earnings through 2013. In 2005, $35 million of after-tax losses were reclassified to earnings.

Credit Risk

Our utility and non-utility businesses are exposed to credit risk if customers or counterparties do not comply with their contractual obligations. We maintain credit policies that significantly minimize overall credit risk. These policies include an evaluation of potential customers' and counterparties' financial condition, credit rating, collateral requirements or other credit enhancements such as letters of credit or guarantees. We generally use standardized agreements that allow the netting of positive and negative transactions associated with a single counterparty.

Interest Rate Risk

We use interest rate swaps, treasury locks and other derivatives to hedge the risk associated with interest rate market volatility. In 2004 and 2000, we entered into a series of interest rate derivatives to limit our sensitivity to market interest rate risk associated with the issuance of long-term debt. Such instruments were designated as cash flow hedges. We subsequently issued long-term debt and terminated these hedges at a cost that is included in other comprehensive loss. Amounts recorded in other comprehensive loss will be reclassified to interest expense as the related interest affects earnings through 2030. In 2006, we estimate reclassifying $4 million of losses to earnings.

Foreign Currency Risk

DTE Energy Trading has foreign currency forward contracts to hedge fixed Canadian dollar commitments existing under power purchase and sale contracts and gas transportation contracts. We entered into these contracts to mitigate any price volatility with respect to fluctuations of the Canadian dollar relative to the U.S. dollar. Certain of these contracts were designated as cash flow hedges with changes in fair value recorded to other comprehensive income. Amounts recorded to other comprehensive income are classified to operating revenues or fuel, purchased power and gas expense when the related hedged item affects earnings.

Fair Value of Other Financial Instruments

The fair value of financial instruments is determined by using various market data and other valuation techniques. The table below shows the fair value relative to the carrying value for long-term debt securities. The carrying value of certain other financial instruments, such as notes payable, customer deposits and notes receivable approximate fair value and are not shown.

	2005		2004	
	Fair Value	**Carrying Value**	Fair Value	Carrying Value
Long-Term Debt	**$7.9 billion**	**$7.7 billion**	$8.5 billion	$8.0 billion

NOTE 13 — COMMITMENTS AND CONTINGENCIES

Synthetic Fuel Operations

We partially own nine synthetic fuel production facilities. Synfuel facilities chemically change coal, including waste and marginal coal, into a synthetic fuel as determined under applicable Internal Revenue Service rules. Production tax credits are provided for the production and sale of solid synthetic fuels produced from coal. To qualify for the production tax credits, the synthetic fuel must meet three primary conditions: (1) there must be a significant chemical change in the coal feedstock, (2) the product must be sold to an unaffiliated entity, and (3) the production facility must have been placed in service before July 1, 1998. In addition to meeting the qualifying conditions for years through 2005, a taxpayer must have sufficient taxable income to earn the production tax credits.

To reduce U.S. dependence on imported oil, the Internal Revenue Code provides production tax credits as an incentive for taxpayers to produce fuels from alternative sources. This incentive is not deemed necessary if the price of oil increases and provides a natural market for these fuels. As such, the tax credit in a given year is reduced if the Reference Price of oil within that year exceeds a threshold price. The Reference Price of a barrel of oil is an estimate of the annual average wellhead price per barrel for domestic crude oil. During 2005 the monthly average wellhead price per barrel of oil for the year was approximately $6 lower than the NYMEX price for light, sweet crude oil. The threshold price at which the credit begins to be reduced was set in 1980 and is adjusted annually for inflation. For 2006, we estimate the threshold price at which the tax credit would begin to be reduced is $53 per barrel and would be completely phased out if the Reference Price reached $67 per barrel. As of February 28, 2006, the realized and unrealized NYMEX daily closing price of a barrel of oil was $65.08, equating to an estimated Reference Price of $59, which is within the phase-out range. We cannot predict with any accuracy the future price of a barrel of oil. If, however, the Reference Price remained at this level throughout the remainder of 2006, we would experience a partial phase out of production tax credits.

Numerous events have increased domestic crude oil prices, including terrorism, storm-related supply disruptions and worldwide demand. If the credit is reduced or eliminated in future years, our financial statements may be negatively impacted. We continue to evaluate the current volatility in oil prices and alternatives available to mitigate our exposure to oil prices. To manage our exposure to oil prices in 2006 and 2007, we entered into oil-related derivative contracts for a portion of our exposure. See Note 12.

Through December 31, 2005 we have generated and recorded approximately $557 million in synfuel tax credits.

Environmental

Electric Utility

Air - Detroit Edison is subject to EPA ozone transport and acid rain regulations that limit power plant emissions of sulfur dioxide and nitrogen oxides. In March 2005, EPA issued additional emission reduction regulations relating to ozone, fine particulate, regional haze and mercury air pollution. The new rules will lead to additional controls on fossil-fueled power plants to reduce nitrogen oxide, sulfur dioxide and mercury emissions. To comply with these requirements, Detroit Edison has spent approximately $644 million through 2005. We estimate Detroit Edison future capital expenditures at up to $218 million in 2006 and up to $2.2 billion of additional capital expenditures through 2018 to satisfy both the existing and proposed new control requirements. Under the June 2000 Michigan restructuring legislation, beginning January 1, 2004, annual return of and on this capital expenditure could be deferred in ratemaking, until December 31, 2005, the expiration of the rate cap period.

Water - Detroit Edison is required to examine alternatives for reducing the environmental impacts of the cooling water intake structures at several of its facilities. Based on the results of the studies to be conducted over the next several years, Detroit Edison may be required to install additional control technologies to reduce the impacts of the intakes. It is estimated that we will incur up to $50 million over the next four to six years in additional capital expenditures for Detroit Edison.

Contaminated Sites - Detroit Edison conducted remedial investigations at contaminated sites, including two former MGP sites, the area surrounding an ash landfill and several underground and aboveground storage tank locations. The findings of these investigations indicated that the estimated cost to remediate these sites is approximately $13 million which was accrued in 2005 and is expected to be incurred over the next several years.

Gas Utility

Contaminated Sites - Prior to the construction of major interstate natural gas pipelines, gas for heating and other uses was manufactured locally from processes involving coal, coke or oil. Gas Utility owns, or previously owned, 15 such former manufactured gas plant (MGP) sites. Investigations have revealed contamination related to the by-products of gas manufacturing at each site. In addition to the MGP sites, we are also in the process of cleaning up other contaminated sites. Cleanup activities associated with these sites will be conducted over the next several years.

In 1993, a cost deferral and rate recovery mechanism was approved by the MPSC for investigation and remediation costs incurred at former MGP sites in excess of this reserve. Gas Utility employed outside consultants to evaluate remediation alternatives for these sites, to assist in estimating its potential liabilities and to review its archived insurance policies. As a result of these studies, Gas Utility accrued an additional liability and a corresponding regulatory asset of $35 million during 1995. During 2005, we spent approximately $4 million investigating and remediating these former MGP sites. In December 2005, we retained multiple environmental consultants to estimate the projected cost to remediate each MGP site. We accrued an additional $9 million in remediation liabilities associated with two of our MGP sites, to increase the reserve balance to $35 million at December 31, 2005.

Any significant change in assumptions, such as remediation techniques, nature and extent of contamination and regulatory requirements, could impact the estimate of remedial action costs for the sites and affect the Company’s financial position and cash flows. However, we anticipate the cost deferral and rate recovery mechanism approved by the MPSC will prevent environmental costs from having a material adverse impact on our results of operations.

Other

Our non-utility affiliates are subject to a number of environmental laws and regulations dealing with the protection of the environment from various pollutants. We are in the process of installing new environmental equipment at our coke battery facilities in Michigan. We expect the projects to be completed within two years at a cost of approximately $25 million. Our other non-utility affiliates are substantially in compliance with all environmental requirements.

Guarantees

In certain circumstances we enter into contractual guarantees. We may guarantee another entity’s obligation in the event it fails to perform. We may provide guarantees in certain indemnification agreements. Finally, we may provide indirect guarantees for the indebtedness of others. Below are the details of specific material guarantees we currently provide. Our other guarantees are not individually material and total approximately $36 million at December 31, 2005.

Sale of Interests in Synfuel Facilities

We have provided certain guarantees and indemnities in conjunction with the sales of interests in our synfuel facilities. The guarantees cover general commercial, environmental, oil price and tax-related exposure and will survive until 90 days after expiration of all applicable statute of limitations, or indefinitely, depending on the nature of the guarantee. We estimate that our maximum liability under these guarantees at December 31, 2005 is $1.8 billion.

Parent Company Guarantee of Subsidiary Obligations

We have issued guarantees for the benefit of various non-utility subsidiary transactions. In the event that DTE Energy's credit rating is downgraded below investment grade, certain of these guarantees would require us to post cash or letters of credit valued at approximately $536 million at December 31, 2005. This estimated amount fluctuates based upon commodity prices (primarily power and gas) and the provisions and maturities of the underlying agreements.

Personal Property Taxes

Detroit Edison, MichCon and other Michigan utilities have asserted that Michigan's valuation tables result in the substantial overvaluation of utility personal property. Valuation tables established by the Michigan State Tax Commission (STC) are used to determine the taxable value of personal property based on the property's age. In November 1999, the STC approved new valuation tables that more accurately recognize the value of a utility's personal property. The new tables became effective in 2000 and are currently used to calculate property tax expense. However, several local taxing jurisdictions have taken legal action attempting to prevent the STC from implementing the new valuation tables and have continued to prepare assessments based on the superseded tables. The legal actions regarding the appropriateness of the new tables were before the Michigan Tax Tribunal (MTT) which, in April 2002, issued a decision essentially affirming the validity of the STC's new tables. In June 2002, petitioners in the case filed an appeal of the MTT's decision with the Michigan Court of Appeals. In January 2004, the Michigan Court of Appeals upheld the validity of the new tables. With no further appeal by the petitioners available, the MTT began to schedule utility personal property valuation cases for Prehearing General Calls. After a period of abeyance the MTT issued a scheduling order in a significant number of Detroit Edison and MichCon appeals that set litigation calendars for these cases extending into mid-2006. After an extended period of settlement discussions, a Memorandum of Understanding has been reached with six principals in the litigation and the Michigan Department of Treasury that is expected to lead to settlement of all outstanding property tax disputes on a global basis.

On December 8, 2005 executed Stipulations for Consent Judgment, Consent Judgments, and Schedules to Consent Judgment were filed with the MTT on behalf of Detroit Edison, MichCon and a significant number of the largest jurisdictions, in terms of tax dollars, involved in the litigation. The filing of these documents fulfilled the requirements of the global settlement agreement and resolves a number of claims by the litigants against each other including both property and non-property issues. The global settlement agreement results in an pre-tax economic benefit to DTE Energy of $43 million that includes the release of a litigation reserve.

Other Commitments

Detroit Edison has an Energy Purchase Agreement to purchase steam and electricity from the Greater Detroit Resource Recovery Authority (GDRRA). Under the Agreement, Detroit Edison will purchase steam through 2008 and electricity through June 2024. In 1996, a special charge to income was recorded that included a reserve for steam purchase commitments in excess of replacement costs from 1997 through 2008. The reserve for steam purchase commitments is being amortized to fuel, purchased power and gas expense with non-cash accretion expense being recorded through 2008. We purchased $42 million of steam and electricity in 2005 and 2004 and $39 million in 2003. We estimate steam and electric purchase commitments through 2024 will not exceed $427 million. As discussed in Note 3, in January 2003, we sold the steam heating business of Detroit Edison to Thermal Ventures II, LP. Due to terms of the sale, Detroit Edison remains contractually obligated to buy steam from GDRRA until 2008 and recorded an additional liability of $20 million for future commitments. Also, we have guaranteed bank loans that Thermal Ventures II, LP may use for capital improvements to the steam heating system.

In 2004, we modified our future purchase commitments under a transportation agreement with an interstate pipeline company and terminated a related long-term gas exchange (storage) agreement. Under the gas exchange agreement, we received gas from the customer during the summer injection period and redelivered the gas during the winter heating season. The agreements were at rates that were not reflective of current market conditions and had been fair valued under accounting principles generally accepted in the U.S. In 2002, the fair value of the transportation agreement was frozen when it no longer met the definition of a derivative as a result of FERC Order 637. The fair value amounts were being amortized to income over the life of the related agreements, representing a net liability of approximately $75 million as of December 31, 2003. As a result of the contract modification and termination, we recorded an adjustment to the net liability increasing 2004 earnings by $48 million, net of taxes.

As of December 31, 2005, we were party to numerous long-term purchase commitments relating to a variety of goods and services required for our business. These agreements primarily consist of fuel supply commitments and energy trading contracts. We estimate that these commitments will be approximately $6.7 billion through 2051. We also estimate that 2006 base level capital expenditures will be $1.2 billion. We have made certain commitments in connection with expected capital expenditures.

Bankruptcies

We purchase and sell electricity, gas, coal, coke and other energy products from and to numerous companies operating in the steel, automotive, energy, retail and other industries. Certain of our customers have filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code. We regularly review contingent matters relating to these customers and our purchase and sale contracts and we record provisions for amounts considered at risk of probable loss. We believe our previously accrued amounts are adequate for probable losses. The final resolution of these matters is not expected to have a material effect on our financial statements.

Other

We are involved in certain legal, regulatory, administrative and environmental proceedings before various courts, arbitration panels and governmental agencies concerning claims arising in the ordinary course of business. These proceedings include certain contract disputes, environmental reviews and investigations, audits, inquiries from various regulators, and pending judicial matters. We cannot predict the final disposition of such proceedings. We regularly review legal matters and record provisions for claims that are considered probable of loss. The resolution of pending proceedings is not expected to have a material effect on our operations or financial statements in the period they are resolved.

See Notes 4 and 5 for a discussion of contingencies related to Regulatory Matters and Nuclear Operations.

NOTE 14 — RETIREMENT BENEFITS AND TRUSTEED ASSETS

Measurement Date

In the fourth quarter of 2004, we changed the date for actuarial measurement of our obligations for benefit programs from December 31 to November 30. We believe the one-month change of the measurement date is a preferable change as it allows time for management to plan and execute its review of the completeness and accuracy of its benefit programs results and to fully reflect the impact on its financial results. The change did not have a material effect on retained earnings as of January 1, 2004, and income from continuing operations, net income and related per share amounts for any interim period in 2004. Accordingly, all amounts reported in the following tables for balances as of December 31, 2005 and December 31, 2004 are based on measurement dates of November 30, 2005 and November 30, 2004, respectively. Amounts reported in tables for the year ended December 31, 2005 are based on a measurement date of November 30, 2004. Amounts reported in tables for the year ended December 31, 2004 are based on a measurement date of December 31,

2003. Amounts reported in tables for the year ended December 31, 2003 are based on a measurement date of December 31, 2002.

Qualified and Nonqualified Pension Plan Benefits

We have defined benefit retirement plans for eligible represented and nonrepresented employees. The plans are noncontributory, cover substantially all employees and provide retirement benefits based on the employees' years of benefit service, average final compensation and age at retirement. Certain represented and nonrepresented employees are covered under cash balance benefits based on annual employer contributions and interest credits. Our policy is to fund pension costs by contributing the minimum amount required by the Employee Retirement Income Security Act and additional amounts when we deem appropriate. We do not anticipate making a contribution to our qualified pension plans in 2006.

We also maintain supplemental nonqualified, noncontributory, retirement benefit plans for selected management employees. These plans provide for benefits that supplement those provided by DTE Energy's other retirement plans.

Net pension cost includes the following components:

	Qualified Pension Plans			Nonqualified Pension Plans		
(in Millions)	**2005**	2004	2003	**2005**	2004	2003
Service Cost	**$ 64**	$ 58	$ 48	**$ 2**	$ 2	$ 2
Interest Cost	**169**	168	164	**3**	3	4
Expected Return on Plan Assets	**(218)**	(216)	(211)	**-**	-	-
Amortization of						
Net loss	**67**	63	38	**1**	1	1
Prior service cost	**8**	8	8	**-**	-	-
Net Pension Cost	**$ 90**	$ 81	$ 47	**$ 6**	$ 6	$ 7

The following table reconciles the obligations, assets and funded status of the plans as well as the amounts recognized as prepaid pension cost or pension liability in the consolidated statement of financial position at December 31

(in Millions)	Qualified Pension Plans 2005	Qualified Pension Plans 2004	Nonqualified Pension Plans 2005	Nonqualified Pension Plans 2004
Accumulated Benefit Obligation-End of Period	**$ 2,741**	$ 2,689	**$ 61**	$ 54
Projected Benefit Obligation-Beginning of Period	**$ 2,899**	$ 2,745	**$ 56**	$ 59
Service Cost	**64**	58	**2**	2
Interest Cost	**169**	168	**3**	3
Actuarial Loss (Gain)	**49**	76	**10**	(4)
Benefits Paid	**(168)**	(149)	**(4)**	(4)
Plan Amendments	**—**	1	**—**	—
Projected Benefit Obligation-End of Period	**$ 3,013**	$ 2,899	**$ 67**	$ 56
Plan Assets at Fair Value-Beginning of Period	**$ 2,565**	$ 2,348	**$ —**	$ —
Actual Return on Plan Assets	**220**	196	**—**	—
Company Contributions	**—**	170	**4**	4
Benefits Paid	**(168)**	(149)	**(4)**	(4)
Plan Assets at Fair Value-End of Period	**$ 2,617**	$ 2,565	**$ —**	$ —
Funded Status of the Plans	**$ (396)**	$ (334)	**$ (67)**	$ (56)
Unrecognized				
Net loss	**1,023**	1,043	**23**	15
Prior service cost	**27**	34	**2**	1
Net Amount Recognized at Measurement Date	**654**	743	**(42)**	(40)
December Adjustments	**—**	—	**1**	1
Net Amount Recognized-End of Period	**$ 654**	$ 743	**$ (41)**	$ (39)
Amount Recorded as				
Prepaid pension assets	**$ 186**	$ 184	**$ —**	$ —
Accrued pension liability	**(224)**	(212)	**(60)**	(53)
Regulatory asset	**532**	594	**12**	11
Accumulated other comprehensive loss	**129**	139	**5**	2
Intangible asset	**31**	38	**2**	1
	$ 654	$ 743	**$ (41)**	$ (39)

Assumptions used in determining the projected benefit obligation and net pension costs are listed below:

	2005	2004	2003
Projected Benefit Obligation			
Discount rate	**5.90%**	6.00%	6.25%
Annual increase in future compensation levels	**4.0%**	4.0%	4.0%
Net Pension Costs			
Discount rate	**6.00%**	6.25%	6.75%
Annual increase in future compensation levels	**4.0%**	4.0%	4.0%
Expected long-term rate of return on Plan assets	**9.0%**	9.0%	9.0%

At December 31, 2005, the benefits related to our qualified and nonqualified plans expected to be paid in each of the next five years and in the aggregate for the five fiscal years thereafter are as follows:

(in Millions)	
2006	$ 174
2007	177
2008	183
2009	188
2010	193
2011 - 2015	1,046
Total	$ 1,961

We employ a consistent formal process in determining the long-term rate of return for various asset classes. We evaluate input from our consultants, including their review of historic financial market risks and returns and long-term historic relationships between the asset classes of equities, fixed income and other assets, consistent with the widely accepted capital market principle that asset classes with higher volatility generate a greater return over the long-term. Current market factors such as inflation, interest rates, asset class risks and asset class returns are evaluated and considered before long-term capital market assumptions are determined. The long-term portfolio return is also established employing a consistent formal process, with due consideration of diversification, active investment management and rebalancing. Peer data is reviewed to check for reasonableness .

We employ a total return investment approach whereby a mix of equities, fixed income and other investments are used to maximize the long-term return of plan assets consistent with prudent levels of risk. The intent of this strategy is to minimize plan expenses over the long-term. Risk tolerance is established through consideration of future plan cash flows, plan funded status, and corporate financial considerations. The investment portfolio contains a diversified blend of equity, fixed income and other investments. Furthermore, equity investments are diversified across U.S. and non-U.S. stocks, growth and value investment styles, and large and small market capitalizations. Other assets such as private equity and absolute return funds are used judiciously to enhance long-term returns while improving portfolio diversification. Derivatives may be used to gain market exposure in an efficient and timely manner; however, derivatives may not be used to leverage the portfolio beyond the market value of the underlying investments. Investment risk is measured and monitored on an ongoing basis through annual liability measurements, periodic asset/liability studies, and quarterly investment portfolio reviews.

Our plans' weighted-average asset allocations by asset category at December 31 were as follows:

	2005	2004
Equity Securities	68%	69%
Debt Securities	27	26
Other	5	5
	100%	100%

Our plans' weighted-average asset target allocations by asset category at December 31, 2005 were as follows:

Equity Securities	65%
Debt Securities	28
Other	7
	100%

In December 2002, we recognized an additional minimum pension liability as required under SFAS No. 87, *Employers' Accounting for Pensions.* An additional pension liability may be required when the accumulated benefit obligation of the plan exceeds the fair value of plan assets. Under SFAS No. 87, we recorded an additional minimum pension liability, an intangible asset and other comprehensive loss. In 2003, we reclassified $572 million of other comprehensive loss related to Detroit Edison's minimum pension liability to a regulatory asset after the MPSC Staff provided an opinion that the MPSC's traditional rate setting process allowed for the recovery of pension costs as measured by SFAS No. 87. The additional minimum pension liability, regulatory asset, intangible asset and other comprehensive loss are adjusted in December of each year based on the plans' funded status.

We also sponsor defined contribution retirement savings plans. Participation in one of these plans is available to substantially all represented and nonrepresented employees. We match employee contributions up to certain predefined limits based upon eligible compensation, the employee's contribution rate and, in some cases, years of credited service. The cost of these plans was $29 million in 2005, $28 million in 2004 and $26 million in 2003.

Other Postretirement Benefits

We provide certain postretirement health care and life insurance benefits for employees who are eligible for these benefits. Our policy is to fund certain trusts to meet our postretirement benefit obligations. Separate qualified Voluntary Employees Beneficiary Association (VEBA) trusts exist for represented and nonrepresented employees. At the discretion of management, we may make up to a $120 million contribution to our VEBA trusts in 2006.

Net postretirement cost includes the following components:

(in Millions)	**2005**	2004	2003
Service Cost	**$ 55**	$ 41	$ 37
Interest Cost	**105**	92	87
Expected Return on Plan Assets	**(70)**	(56)	(47)
Amortization of			
Net loss	**60**	43	31
Prior service cost	**(2)**	(3)	(3)
Net transition obligation	**7**	8	13
Net Postretirement Cost	**$ 155**	$ 125	$ 118

The following table reconciles the obligations, assets and funded status of the plans including amounts recorded as accrued postretirement cost in the consolidated statement of financial position at December 31:

(in Millions)	2005	2004
Accumulated Postretirement Benefit Obligation-Beginning of Period	**$ 1,793**	$ 1,582
Service Cost	**55**	41
Interest Cost	**105**	92
Actuarial Loss	**136**	146
Plan Amendments	**(10)**	7
Benefits Paid	**(88)**	(75)
Accumulated Postretirement Benefit Obligation-End of Period	**$ 1,991**	$ 1,793
Plan Assets at Fair Value-Beginning of Period	**$ 679**	$ 586
Actual Return on Plan Assets	**61**	53
Company Contributions	**40**	40
Benefits Paid	**(67)**	—
Plan Assets at Fair Value-End of Period	**$ 713**	$ 679
Funded Status of the Plans	**$ (1,278)**	$ (1,114)
Unrecognized		
Net loss	**896**	811
Prior service cost	**(12)**	(8)
Net transition obligation	**46**	58
Accrued Postretirement Liability at Measurement Date	**(348)**	(253)
December Adjustments	**(58)**	(20)
Accrued Postretirement Liability-End of Period	**$ (406)**	$ (273)

Assumptions used in determining the projected benefit obligation and net benefit costs are listed below:

	2005	2004	2003
Projected Benefit Obligation			
Discount rate	**5.90%**	6.00%	6.25%
Net Benefit Costs			
Discount rate	**6.00%**	6.25%	6.75%
Expected long-term rate of return on Plan assets	**9.0%**	9.0%	9.0%

Benefit costs were calculated assuming health care cost trend rates beginning at 9% for 2006 and decreasing to 5% in 2011 and thereafter for persons under age 65 and decreasing from 8% to 5% for persons age 65 and over. A one-percentage-point increase in health care cost trend rates would have increased the total service cost and interest cost components of benefit costs by $32 million and increased the accumulated benefit obligation by $244 million at December 31, 2005. A one-percentage-point decrease in the health care cost trend rates would have decreased the total service and interest cost components of benefit costs by $20 million and would have decreased the accumulated benefit obligation by $203 million at December 31, 2005.

At December 31, 2005, the benefits expected to be paid, including prescription drug benefits, in each of the next five years and in the aggregate for the five fiscal years thereafter are as follows:

(in Millions)		
2006	$	**111**
2007		**116**
2008		**120**
2009		**125**
2010		**128**
2011 - 2015		**670**
Total	**$**	**1,270**

The process used in determining the long-term rate of return for assets and the investment approach for our other postretirement benefits plans is similar to those previously described for our qualified pension plans.

Our plans' weighted-average asset allocations by asset category at December 31 were as follows:

	2005	2004
Equity Securities	**68%**	68%
Debt Securities	**28**	28
Other	**4**	4
	100%	100%

Our plans' weighted-average asset target allocations by asset category at December 31, 2005 were as follows:

Equity Securities	**65%**
Debt Securities	**28**
Other	**7**
	100%

In December 2003, the Medicare Act was signed into law which provides for a non-taxable federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least "actuarially equivalent" to the benefit established by law. As discussed in Note 2, we adopted FSP No. 106-2 in 2004, which provides guidance on the accounting for the Medicare Act. As a result of the adoption, our accumulated postretirement benefit obligation for the subsidy related to benefits attributed to past service was reduced by approximately $95 million at January 1, 2004 and was accounted for as an actuarial gain. The effects of the subsidy reduced net periodic postretirement benefit costs by $20 million in 2005 and $16 million in 2004.

At December 31, 2005, the gross amount of federal subsidies expected to be received in each of the next five years and in the aggregate for the five fiscal years thereafter was as follows:

(in Millions)		
2006	**$**	**6**
2007		**4**
2008		**5**
2009		**6**
2010		**5**
2011 - 2015		**35**
Total	**$**	**61**

Grantor Trust

MichCon maintains a Grantor Trust that invests in life insurance contracts and income securities. Employees and retirees have no right, title or interest in the assets of the Grantor Trust, and MichCon can revoke the trust subject to providing the MPSC with prior notification. We account for our investment at fair value with unrealized gains and losses recorded to earnings.

NOTE 15 — STOCK-BASED COMPENSATION

The DTE Energy Stock Incentive Plan permits the grant of incentive stock options, non-qualifying stock options, stock awards, performance shares and performance units. A maximum of 18 million shares of common stock may be issued under the plan. Participants in the plan include our employees and members of our Board of Directors. As of December 31, 2005, no performance units have been granted under the plan.

Options

Options are exercisable according to the terms of the individual stock option award agreements and expire 10 years after the date of the grant. The option exercise price equals the fair value of the stock on the date that the option was granted. Stock option activity was as follows:

	Number of Options	Weighted Average Exercise Price
Outstanding at December 31, 2002 (2,285,323 exercisable)	5,480,595	$ 39.87
Granted	1,654,879	$ 40.56
Exercised	(329,528)	$ 35.88
Canceled	(152,824)	$ 42.67
Outstanding at December 31, 2003 (3,506,038 exercisable)	6,653,122	$ 40.18
Granted	1,300,900	$ 39.41
Exercised	(891,353)	$ 34.94
Canceled	(356,000)	$ 43.06
Outstanding at December 31, 2004 (3,939,939 exercisable)	6,706,669	$ 40.57
Granted	**955,899**	**$ 44.79**
Exercised	**(1,291,645)**	**$ 39.92**
Canceled	**(134,580)**	**$ 42.33**
Outstanding at December 31, 2005 (4,029,444 exercisable at a weighted average exercise price of $40.88)	**6,236,343**	**$ 41.31**

The number, weighted average exercise price and weighted average remaining contractual life of options outstanding were as follows:

Range of Exercise Prices	**Number of Options**	**Weighted Average Exercise Price**	**Weighted Average Remaining Contractual Life**
$27.62 - $38.04	423,473	$ 31.34	3.97 years
$38.60 - $42.44	3,728,512	$ 40.64	6.76 years
$42.60 - $44.54	482,110	$ 42.65	5.35 years
$44.56 - $48.00	1,602,248	$ 45.09	7.47 years
	6,236,343	$ 41.31	6.64 years

We account for option awards under APB Opinion 25. Accordingly, no compensation expense has been recorded for options granted. As required by SFAS No. 123, we have determined the fair value for these options at the date of grant using a Black-Scholes based option pricing model and the following assumptions:

	2005	2004	2003
Risk-free interest rate	**3.93%**	3.55%	2.93%
Dividend yield	**4.60%**	5.23%	4.97%
Expected volatility	**19.56%**	20.00%	20.89%
Expected life	**6 years**	6 years	6 years
Fair value per option	**$ 5.89**	$ 4.46	$ 4.78

Stock Awards

Stock awards granted under the plan are restricted for varying periods, which are generally for three years. Participants have all rights of a shareholder with respect to a stock award, including the right to receive dividends and vote the shares. Prior to vesting in stock awards, the participant: (i) may not sell, transfer, pledge, exchange or otherwise dispose of shares; (ii) shall not retain custody of the share certificates; and (iii) will deliver to us a stock power with respect to each stock award.

The stock awards are recorded at cost that approximates fair value on the date of grant. We account for stock awards as unearned compensation, which is recorded as a reduction to common stock. The cost is amortized to compensation expense over the vesting period. Stock award activity for the years ended December 31 was:

	2005	2004	2003
Restricted common shares awarded	**288,360**	209,650	102,060
Weighted average market price of shares awarded	**$ 44.95**	$ 39.95	$ 41.39
Compensation cost charged against income (in thousands)	**$ 7,747**	$ 5,616	$ 6,366

Performance Share Awards

Performance shares awarded under the plan are for a specified number of shares of common stock that entitles the holder to receive a cash payment, shares of common stock or a combination thereof. The final value of the award is determined by the achievement of certain performance objectives. The awards vest at the end of a specified period, usually three years. We account for performance share awards by accruing compensation expense over the vesting period based on: (i) the number of shares expected to be paid which is based on the probable achievement of performance objectives; and (ii) the fair value of the shares. For 2005, 2004 and 2003, we recorded compensation expense totaling $5 million, $6 million and $6 million, respectively.

During the vesting period, the recipient of a performance share award has no shareholder rights. However, recipients will be paid an amount equal to the dividend equivalent on such shares. Performance share awards are nontransferable and are subject to risk of forfeiture. As of December 31, 2005, there were 803,071 performance share awards outstanding.

NOTE 16 — SEGMENT AND RELATED INFORMATION

We operate our businesses through three strategic business units, Electric Utility, Gas Utility and Non-Utility Operations. The balance of our business consists of Corporate & Other. Based on this structure, we set strategic goals, allocate resources and evaluate performance. This results in the following reportable segments:

Electric Utility

- Consists of Detroit Edison, the company's electric utility whose operations include the power generation and electric distribution facilities that service approximately 2.2 million residential, commercial and industrial customers throughout southeastern Michigan.

Gas Utility

- Consists of the gas distribution services provided by MichCon, a gas utility that purchases, stores and distributes natural gas throughout Michigan to approximately 1.3 million residential, commercial and industrial customers and Citizens Gas Fuel Company, a gas utility that distributes natural gas in Adrian, Michigan.

Non-utility Operations

- *Power and Industrial Projects*, primarily consisting of synfuel projects, on-site energy services, steel-related projects, power generation with services, and waste coal recovery operations;
- *Unconventional Gas Production,* primarily consisting of natural gas exploration, development and production; and
- *Fuel Transportation and Marketing*, primarily consisting of energy marketing and trading operations, coal transportation and marketing, and gas pipelines, processing and storage.

Corporate & Other, primarily consisting of corporate support functions and certain energy related investments.

The income tax provisions or benefits of DTE Energy's subsidiaries are determined on an individual company basis and recognize the tax benefit of production tax credits and net operating losses. The subsidiaries record income tax payable to or receivable from DTE Energy resulting from the inclusion of its taxable income or loss in DTE Energy's consolidated tax return.

Inter-segment billing for goods and services exchanged between segments is based upon tariffed or market-based prices of the provider and primarily consists of power sales, gas sales and coal transportation services in the following segments:

(in Millions)	**2005**	2004	2003
Electric Utility	**$ 207**	$ 218	$ 69
Unconventional Gas Production	**154**	121	114
Fuel Transportation and Marketing	**268**	253	66
	$ 629	$ 592	$ 249

Financial data of the business segments follows:

(in Millions) **2005**	Operating Revenue	Depreciation, Depletion & Amortization	Interest Income	Interest Expense	Income Taxes	Net Income	Total Assets	Goodwill	Capital Expenditures
Electric Utility	$ 4,462	$ 640	$ (3)	$ 267	$ 149	$ 277	$ 13,112	$ 1,207	$ 722
Gas Utility	2,138	95	(10)	58	(2)	37	3,101	772	128
Non-utility Operations:									
Power and Industrial Projects	1,356	107	(41)	21	89	308	2,117	41	31
Unconventional Gas Production	74	20	—	8	1	4	434	8	144
Fuel Transportation and Marketing	1,684	7	(6)	21	(1)	2	2,207	29	36
	3,114	134	(47)	50	89	314	4,758	78	211
Corporate & Other	10	—	(40)	187	(34)	(52)	2,358	—	4
Reconciliation and Eliminations	(702)	—	43	(43)	—	—	—	—	—
Total from Continuing Operations	$ 9,022	$ 869	$ (57)	$ 519	$ 202	576	23,329	2,057	1,065
Discontinued Operations (Note 3)						(36)	6	—	—
Cumulative Effect of Accounting Change (Note 2)						(3)	—	—	—
Total						$ 537	$ 23,335	$ 2,057	$ 1,065

(in Millions) 2004	Operating Revenue	Depreciation, Depletion & Amortization	Interest Income	Interest Expense	Income Taxes	Net Income	Total Assets	Goodwill	Capital Expenditures
Electric Utility	$3,568	$ 523	$ —	$ 280	$ 64	$ 150	$ 12,708	$ 1,202	$ 702
Gas Utility	1,682	103	(9)	58	(9)	20	2,816	772	113
Non-utility Operations:									
Power and Industrial Projects	1,100	89	(43)	35	42	179	1,841	41	24
Unconventional Gas Production	71	18	—	10	3	6	301	8	38
Fuel Transportation and Marketing	1,254	6	(4)	8	64	118	1,280	28	24
	2,425	113	(47)	53	109	303	3,422	77	86
Corporate & Other	17	3	(48)	174	10	(12)	2,284	—	2
Reconciliation and Eliminations	(621)	—	49	(49)	—	—	—	—	—
Total from Continuing Operations	$ 7,071	$ 742	$(55)	$ 516	$ 174	461	21,230	2,051	903
Discontinued Operations (Note 3)						(30)	67	16	1
Total						$ 431	$21,297	$2,067	$ 904

(in Millions) 2003	Operating Revenue	Depreciation, Depletion & Amortization	Interest Income	Interest Expense	Income Taxes	Net Income	Total Assets	Goodwill	Capital Expenditures
Electric Utility	$3,695	$ 473	$ (7)	$ 284	$ 145	$252	$12,502	$ 1,202	$ 580
Gas Utility	1,498	101	(10)	58	—	29	2,719	776	99
Non-utility Operations:									
Power and Industrial Projects	938	90	(16)	21	(271)	197	1,690	41	26
Unconventional Gas Production	70	17	—	7	5	12	282	8	28
Fuel Transportation and Marketing	1,061	4	(3)	6	41	69	1,089	28	13
	2,069	111	(19)	34	(225)	278	3,061	77	67
Corporate & Other	16	—	(33)	201	(36)	(65)	2,400	—	4
Reconciliation and Eliminations	(273)	—	32	(32)	—	—	—	—	—
Total from Continuing Operations	$ 7,005	$ 685	$ (37)	$ 545	$(116)	494	20,682	2,055	750
Discontinued Operations (Note 3)						54	71	12	1
Cumulative Effect of Accounting Change (Note 2)						(27)	—	—	—
Total						$521	$ 20,753	$ 2,067	$ 751

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NOTE 17 — SUPPLEMENTARY QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Quarterly earnings per share may not total for the years, since quarterly computations are based on weighted average common shares outstanding during each quarter. Dtech was reported as a discontinued operation beginning in the third quarter 2005, resulting in the adjustment of prior quarterly results. See Note 3.

(in Millions, except per share amounts)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
2005					
Operating Revenues	**$ 2,309**	**$ 1,941**	**$ 2,060**	**$ 2,712**	**$ 9,022**
Operating Income	**$ 224**	**$ 90**	**$ 51**	**$ 581**	**$ 946**
Net Income (Loss)					
From continuing operations	**$ 126**	**$ 33**	**$ 29**	**$ 388**	**$ 576**
Discontinued operations	**(4)**	**(4)**	**(25)**	**(3)**	**(36)**
Cumulative effect of accounting change	**—**	**—**	**—**	**(3)**	**(3)**
Total	**$ 122**	**$ 29**	**$ 4**	**$ 382**	**$ 537**
Basic Earnings (Loss) per Share					
From continuing operations	**$ .72**	**$ .19**	**$ .17**	**$ 2.19**	**$ 3.29**
Discontinued operations	**(.02)**	**(.02)**	**(.15)**	**(.01)**	**(.20)**
Cumulative effect of accounting change	**—**	**—**	**—**	**(.02)**	**(.02)**
Total	**$ .70**	**$ .17**	**$ .02**	**$ 2.16**	**$ 3.07**
Diluted Earnings (Loss) per Share					
From continuing operations	**$ .72**	**$ .19**	**$ .17**	**$ 2.18**	**$ 3.27**
Discontinued operations	**(.02)**	**(.02)**	**(.15)**	**(.02)**	**(.20)**
Cumulative effect of accounting change	**—**	**—**	**—**	**(.02)**	**(.02)**
Total	**$ .70**	**$ .17**	**$ .02**	**$ 2.14**	**$ 3.05**
2004					
Operating Revenues	$ 2,082	$ 1,490	$ 1,586	$ 1,913	$ 7,071
Operating Income	$ 372	$ 106	$ 177	$ 215	$ 870
Net Income (Loss)					
From continuing operations	$ 200	$ 43	$ 97	$ 121	$ 461
Discontinued operations	(10)	(8)	(4)	(8)	(30)
Total	$ 190	$ 35	$ 93	$ 113	$ 431
Basic Earnings (Loss) per Share					
From continuing operations	$ 1.18	$ .25	$ .56	$ .69	$ 2.67
Discontinued operations	(.06)	(.05)	(.02)	(.04)	(.17)
Total	$ 1.12	$ .20	$ .54	$ .65	$ 2.50
Diluted Earnings (Loss) per Share					
From continuing operations	$ 1.17	$ .25	$ .56	$ .69	$ 2.66
Discontinued operations	(.06)	(.05)	(.02)	(.04)	(.17)
Total	$ 1.11	$ .20	$ .54	$ .65	$ 2.49

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

See Item 8. Financial Statements and Supplementary Data for management's evaluation of disclosure controls and procedures, its report on internal control over financial reporting, and its conclusion on changes in internal control over financial reporting.

Item 9B. Other Information

None.

Part III

Item 10. Directors and Executive Officers of the Registrant

Item 11. Executive Compensation

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Item 13. Certain Relationships and Related Transactions

Item 14. Principal Accountant Fees and Services

Information required by Part III (Items 10, 11, 12, 13 and 14) of this Form 10-K is incorporated by reference from DTE Energy's definitive Proxy Statement for its 2006 Annual Meeting of Common Shareholders to be held April 27, 2006. The Proxy Statement will be filed with the Securities and Exchange Commission, pursuant to Regulation 14A, not later than 120 days after the end of our fiscal year covered by this report on Form 10-K, all of which information is hereby incorporated by reference in, and made part of, this Form 10-K, except that the information required by Item 10 with respect to executive officers of the Registrant is included in Part I of this report.

Part IV

Item 15. Exhibits and Financial Statement Schedules

(a) The following documents are filed as part of this Annual Report on Form 10-K.

(1) Consolidated financial statements. See "Item 8 – Financial Statements and Supplementary Data."

(2) Financial statement schedule. See "Item 8 – Financial Statements and Supplementary Data."

(3) Exhibits.

(i) Exhibits filed herewith.

10-60 Second Amendment to the DTE Energy Executive Supplemental Retirement Plan.

10-61 First Amendment to the DTE Energy Company Executive Deferred Compensation Plan effective as of October 1, 2003.

12-36 Computation of Ratio of Earnings to Fixed Charges.

21-1 Subsidiaries of the Company.

23-18 Consent of Deloitte & Touche LLP.

31-21 Chief Executive Officer Section 302 Form 10-K Certification of Periodic Report.

31-22 Chief Financial Officer Section 302 Form 10-K Certification of Periodic Report.

(ii) Exhibits incorporated herein by reference.

3(a) Amended and Restated Articles of Incorporation of DTE Energy Company, dated December 13, 1995 (Exhibit 3-5 to Form 10-Q for quarter ended September 30, 1997).

3(b) Certificate of Designation of Series A Junior Participating Preferred Stock of DTE Energy Company, dated September 23, 1997 (Exhibit 3-6 to Form 10-Q for quarter ended September 30, 1997).

3(c) Rights Agreement, dated September 23, 1997, by and between DTE Energy Company and The Detroit Edison Company, as Rights Agent (Exhibit 4-1 to Form 8-K dated September 22, 1997).

3(d) Bylaws of DTE Energy Company, as amended through February 24, 2005 (Exhibit 3.1 to Form 8-K dated February 24, 2005).

4(a) Amended and Restated Indenture, dated as of April 9, 2001, between DTE Energy Company and The Bank of New York, as trustee (Exhibit 4-1 to Registration No. 333-58834).

4(b) Amended and Restated First Supplemental Indenture, dated as of April 9, 2001, between DTE Energy Company and The Bank of New York, as trustee, creating Remarketed Notes, Series A due 2038 (Exhibit 4-223 to Form 10-Q for quarter ended March 31, 2001).

4(c) Amended and Restated Second Supplemental Indenture, dated as of April 9, 2001, between DTE Energy Company and The Bank of New York, as trustee, creating Remarketed Notes, 1998 Series B (Exhibit 4-224 to Form 10-Q for quarter ended March 31, 2001).

4(d) Third Supplemental Indenture, dated as of April 9, 2001, among DTE Capital Corporation, DTE Energy Company and The Bank of New York, as trustee (Exhibit 4-225 to Form 10-Q for quarter ended March 31, 2001).

4(e) Supplemental Indenture, dated as of May 30, 2001, between DTE Energy Company and The Bank of New York, as trustee, creating 6% Senior Notes due 2004, 6.45% Senior Notes due 2006 and 7.05% Senior Notes due 2011 (Exhibit 4-226 to Form 10-Q for quarter ended June 30, 2001).

4(f) Fourth Supplemental Indenture, dated as of January 15, 2002, between DTE Energy Company and The Bank of New York, as trustee, creating 7.8% Junior Subordinated Debentures due 2032 (Exhibit 4-228 to Form 10-K for year ended December 31, 2001).

4(g) Supplemental Indenture, dated as of April 5, 2002, between DTE Energy Company and The Bank of New York, as trustee, creating 2002 Series A 6.65% Senior Notes due 2009 (Exhibit 4-230 to Form 10-Q for quarter ended March 31, 2002).

4(h) Sixth Supplemental Indenture, dated as of June 25, 2002, between DTE Energy Company and The Bank of New York, as trustee, creating 4.60% Senior Notes due 2007 (Exhibit 4-233 to Form 10-Q for quarter ended June 30, 2002).

4(i)	Supplemental Indenture, dated as of April 1, 2003, between DTE Energy Company and The Bank of New York, as trustee, creating 2003 Series A 6 3/8% Senior Notes due 2033 (Exhibit 4(o) to Form 10-Q for quarter ended March 31, 2003).
4(j)	Supplemental Indenture, dated as of June 1, 2004, between DTE Energy Company and BNY Midwest Trust Company (successor to The Bank of New York), creating 2004 Series C Floating Rate Notes due 2007 (Exhibit 4(p) to Form 10-Q for quarter ended June 30, 2004).
4(k)	Supplemental Indenture, dated as of June 1, 2004, between DTE Energy Company and BNY Midwest Trust Company (successor to The Bank of New York), creating 7.50% Junior Subordinated Debentures due 2044 (Exhibit 4(r) to Form 10-Q for quarter ended June 30, 2004).
4(l)	Amended and Restated Trust Agreement of DTE Energy Trust I, dated as of January 15, 2002 (Exhibit 4-229 to Form 10-K for year ended December 31, 2001).
4(m)	Amended and Restated Trust Agreement of DTE Energy Trust II, dated as of June 1, 2004 (Exhibit 4(q) to Form 10-Q for quarter ended June 30, 2004).
4(n)	Trust Agreement of DTE Energy Trust III (Exhibit 4-21 to Registration Statement on Form S-3 (File No. 333-99955).
10(a)	Form of 1995 Indemnification Agreement between DTE Energy Company and its directors and officers (Exhibit 3L (10-1) to Form 8-B dated January 2, 1996).
10(b)	Form of Indemnification Agreement between The Detroit Edison Company and its officers (Exhibit 10-40 to Form 10-K for year ended December 31, 2000).
10(c)	Certain arrangements pertaining to the employment of Anthony F. Earley, Jr. with The Detroit Edison Company, dated April 25, 1994 (Exhibit 10-53 to The Detroit Edison Company's Form 10-Q for quarter ended March 31, 1994).
10(d)	Certain arrangements pertaining to the employment of Gerard M. Anderson with The Detroit Edison Company, dated October 6, 1993 (Exhibit 10-48 to The Detroit Edison Company's Form 10-K for year ended December 31, 1993).
10(e)	Certain arrangements pertaining to the employment of David E. Meador with The Detroit Edison Company, dated January 14, 1997 (Exhibit 10-5 to Form 10-K for year ended December 31, 1996).
10(f)	Certain arrangements pertaining to the employment of Bruce D. Peterson, dated May 22, 2002 (Exhibit 10-48 to Form 10-Q for quarter ended June 30, 2002).
10(g)	Termination and Consulting Agreement, dated as of October 4, 1999, among DTE Energy Company, MCN Energy Group Inc., DTE Enterprises Inc. and A.R. Glancy, III (Exhibit 10-41 to Form 10-K for year ended December 31, 2001).
10(h)	Amended and Restated Post-Employment Income Agreement, dated March 23, 1998, between The Detroit Edison Company and Anthony F. Earley, Jr. (Exhibit 10-21 to Form 10-Q for quarter ended March 31, 1998).
10(i)	Executive Post-Employment Income Arrangement, dated March 27, 1989, between The Detroit Edison Company and S. Martin Taylor (Exhibit 10-22 to Form 10-Q for quarter ended March 31, 1998).
10(j)	Amended and Restated Executive Incentive Plan of DTE Energy Company, dated February 23, 2000 (Exhibit 10-35 to Form 10-Q for quarter ended March 31, 2000).
10(k)	DTE Energy Company Annual Incentive Plan (Exhibit 10-44 to Form 10-Q for quarter ended March 31, 2001).
10(l)	DTE Energy Company 2001 Stock Incentive Plan (Exhibit 10-43 to Form 10-Q for quarter ended March 31, 2001).

10(m)	DTE Energy Company Deferred Stock Compensation Plan for Non-Employee Directors, effective as of January 1, 1999 (Exhibit 10-30 to Form 10-K for year ended December 31, 1998).
10(n)	DTE Energy Company Retirement Plan for Non-Employee Directors (as amended and restated effective as of December 31, 1998) (Exhibit 10-31 to Form 10-K for year ended December 31, 1998).
10(o)	DTE Energy Company Plan for Deferring the Payment of Directors' Fees (as amended and restated effective as of January 1, 1999) (Exhibit 10-29 to Form 10-K for year ended December 31, 1998).
10(p)	DTE Energy Company Supplemental Savings Plan, effective as of December 6, 2001 (Exhibit 10-44 to Form 10-Q for quarter ended June 30, 2002).
10(q)	Amendment to the DTE Energy Company Supplemental Savings Plan (Exhibit 10-54 to Form 10-Q for quarter ended September 30, 2004).
10(r)	DTE Energy Company Executive Deferred Compensation Plan, effective as of January 1, 2002 (Exhibit 10-45 to Form 10-Q for quarter ended June 30, 2002).
10(s)	Second Amendment to the DTE Energy Company Executive Deferred Compensation Plan (Exhibit 10-55 to Form 10-Q for quarter ended September 30, 2004).
10(t)	DTE Energy Company Supplemental Retirement Plan, effective as of January 1, 2002 (Exhibit 10-46 to Form 10-Q for quarter ended June 30, 2002).
10(u)	Amendment to the DTE Energy Company Supplemental Retirement Plan (Exhibit 10-53 to Form 10-Q for quarter ended September 30, 2004).
10(v)	DTE Energy Company Executive Supplemental Retirement Plan, effective as of January 1, 2001 (Exhibit 10-51 to Form 10-Q for quarter ended September 30, 2004).
10(w)	First Amendment to the DTE Energy Company Executive Supplemental Retirement Plan (Exhibit 10-52 to Form 10-Q for quarter ended September 30, 2004).
10(x)	The Detroit Edison Company Supplemental Long-Term Disability Plan, dated January 27, 1997 (Exhibit 10-4 to Form 10-K for year ended December 31, 1996).
10(y)	Description of Executive Life Insurance Plan (Exhibit 10-47 to Form 10-Q for quarter ended June 30, 2002).
10(z)	Executive Vehicle Plan of The Detroit Edison Company, dated as of September 1, 1999 (Exhibit 10-41 to Form 10-Q for quarter ended March 31, 2001).
10(aa)	DTE Energy Affiliates Nonqualified Plans Master Trust, effective as of May 1, 2003 (Exhibit 10-49 to Form 10-Q for quarter ended March 31, 2003).
10(bb)	Form of Change-in-Control Severance Agreement, dated as of March 11, 2005, between DTE Energy Company and each of Anthony F. Earley, Jr., Gerard M. Anderson, Robert J. Buckler, Stephen E. Ewing and David E. Meador (Exhibit 10-56 to Form 10-K for year ended December 31, 2004).
10(cc)	Form of DTE Energy Five-Year Credit Agreement, dated as of October 17, 2005, by and among DTE Energy, the lenders party thereto, Citibank, N.A., as Administrative Agent, and Barclays Bank PLC and JPMorgan Chase Bank, N. A. as Co-Syndication Agents (Exhibit 10.1 to Form 8-K dated October 17, 2005).
10(dd)	Form of Second Amended and Restated Five-Year Credit Agreement, dated as of October 17, 2005, by and among DTE Energy, the lenders party thereto, Citibank, N.A., as Administrative Agent, and Barclays Bank PLC and JPMorgan Chase Bank, N.A. as Co-Syndication Agents (Exhibit 10.2 to Form 8-K dated October 17, 2005).
10(ee)	Form of Letter of Credit and Reimbursement Agreement, dated as of December 16, 2005, by and

	among DTE Energy, the lenders party thereto, and The Bank of Nova Scotia, as Administrative Agents. (Exhibit 10.1 to Form 8-K dated December 16, 2005).
10(ff)	Form of Director Restricted Stock Agreement (Exhibit 10.1 to Form 8-K dated June 23, 2005).
99(a)	Master Trust Agreement ("Master Trust"), dated as of June 30, 1994, between The Detroit Edison Company and Fidelity Management Trust Company relating to the Savings and Investment Plans (Exhibit 4-167 to Form 10-Q for quarter ended June 30, 1994).
99(b)	First Amendment, dated as of February 1, 1995, to Master Trust (Exhibit 4-10 to Registration No. 333-00023).
99(c)	Second Amendment, dated as of February 1, 1995, to Master Trust (Exhibit 4-11 to Registration No. 333-00023).
99(d)	Third Amendment, effective January 1, 1996, to Master Trust (Exhibit 4-12 to Registration No. 333-00023).
99(e)	Fourth Amendment, dated as of August 1, 1996, to Master Trust (Exhibit 4-185 to Form 10-K for year ended December 31, 1997).
99(f)	Fifth Amendment, dated as of January 1, 1998, to Master Trust (Exhibit 4-186 to Form 10-K for year ended December 31, 1997).
99(g)	Sixth Amendment, dated as of September 1, 1998, to Master Trust (Exhibit 99-15 to Form 10-K for year ended December 31, 2004).
99(h)	Seventh Amendment, dated as of December 15, 1999, to Master Trust (Exhibit 99-16 to Form 10-K for year ended December 31, 2004).
99(i)	Eighth Amendment, dated as of February 1, 2000, to Master Trust (Exhibit 99-17 to Form 10-K for year ended December 31, 2004).
99(j)	Ninth Amendment, dated as of April 1, 2000, to Master Trust (Exhibit 99-18 to Form 10-K for year ended December 31, 2004).
99(k)	Tenth Amendment, dated as of May 1, 2000, to Master Trust (Exhibit 99-19 to Form 10-K for year ended December 31, 2004).
99(l)	Eleventh Amendment, dated as of July 1, 2000, to Master Trust (Exhibit 99-20 to Form 10-K for the year ended December 31, 2004).
99(m)	Twelfth Amendment, dated as of August 1, 2000, to Master Trust (Exhibit 99-21 to Form 10-K for year ended December 31, 2004).
99(n)	Thirteenth Amendment, dated as of December 21, 2001, to Master Trust (Exhibit 99-22 to Form 10-K for year ended December 31, 2004).
99(o)	Fourteenth Amendment, dated as of March 1, 2002, to Master Trust (Exhibit 99-23 to Form 10-K for year ended December 31, 2004).
99(p)	Fifteenth Amendment, dated as of January 1, 2002, to Master Trust (Exhibit 99-24 to Form 10-K for year ended December 31, 2004).
(iii)	**Exhibits furnished herewith.**
32-21	Chief Executive Officer Section 906 Form 10-K Certification of Periodic Report.
32-22	Chief Financial Officer Section 906 Form 10-K Certification of Periodic Report.

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DTE Energy Company

Schedule II – Valuation and Qualifying Accounts

(in Millions)	Year Ending December 31, 2005	2004	2003
Allowance for Doubtful Accounts (shown as deduction from accounts receivable in the consolidated statement of financial position)			
Balance at Beginning of Period	**$ 129**	$ 99	$ 82
Additions:			
Charged to costs and expenses	**106**	108	80
Charged to other accounts (1)	**9**	9	4
Deductions (2)	**(108)**	(87)	(67)
Balance At End of Period	**$ 136**	$ 129	$ 99

(1) Collection of accounts previously written off.

(2) Uncollectible accounts written off.

UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table provides information about Company purchases of equity securities that are registered by the Company pursuant to Section 12 of the Exchange Act for the year ended December 31, 2005:

Period	Total Number of Shares Purchased (1)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Dollar Value that May Yet Be Purchased Under the Plans or Programs (2)
01/01/05 - 01/31/05	—	—	—	$ 700,000,000
02/01/05 - 02/28/05	205,940	$ 43.75	—	700,000,000
03/01/05 - 03/31/05	1,000	45.26	—	700,000,000
04/01/05 – 04/30/05	15,500	45.67	—	700,000,000
05/01/05 – 05/31/05	16,400	46.07	—	700,000,000
06/01/05 – 06/30/05	1,320	47.55	—	700,000,000
07/01/05 – 07/31/05	5,500	47.80	—	700,000,000
08/01/05 – 08/31/05	34,500	45.42	—	700,000,000
09/01/05 – 09/30/05	—	—	—	700,000,000
10/01/05 – 10/31/05	1,200	44.36	—	700,000,000
11/01/05 – 11/30/05	2,500	43.58	—	700,000,000
12/01/05 – 12/31/05	4,500	43.98	—	700,000,000
Total	288,360	44.23	—	

(1) Represents shares of common stock purchased on the open market to provide shares to participants under various employee compensation and incentive programs. These purchases were not made pursuant to a publicly announced plan or program.

(2) In January 2005, the DTE Energy Board authorized the repurchase of up to $700 million in common stock through 2008. The authorization provides Company management with flexibility to pursue share repurchase from time to time, and will depend on future cash flows and investment opportunities.

Signatures

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

DTE ENERGY COMPANY
(Registrant)

Date: March 7, 2006

By /s/ ANTHONY F. EARLEY, JR.
Anthony F. Earley, Jr.
Chairman of the Board and
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

By /s/ ANTHONY F. EARLEY, JR.
Anthony F. Earley, Jr.
Chairman of the Board and
Chief Executive Officer

By /s/ DAVID E. MEADOR
David E. Meador
Executive Vice President and Chief
Financial Officer

By /s/ PETER B. OLEKSIAK
Peter B. Oleksiak
Controller and
Chief Accounting Officer

By /s/JOHN E. LOBBIA
John E. Lobbia, Director

By /s/ GAIL J. McGOVERN
Gail J. McGovern, Director

By /s/ LILLIAN BAUDER
Lillian Bauder, Director

By /s/ EUGENE A. MILLER
Eugene A. Miller, Director

By /s/ ALLAN D. GILMOUR
Allan D. Gilmour, Director

By /s/ CHARLES W. PRYOR, JR.
Charles W. Pryor, Jr., Director

By /s/ ALFRED R. GLANCY III
Alfred R. Glancy III, Director

By /s/ JOSUE ROBLES, JR.
Josue Robles, Jr., Director

By /s/ FRANK M. HENNESSEY
Frank M. Hennessey, Director

By /s/ HOWARD F. SIMS
Howard F. Sims, Director

By /s/ JOE W. LAYMON
Joe W. Laymon, Director

Date: March 7, 2006

Exhibit Index

Exhibit Number	Description
(i)	**Exhibits filed herewith.**
10-60	Second Amendment to the DTE Energy Executive Supplemental Retirement Plan.
10-61	First Amendment to the DTE Energy Company Executive Deferred Compensation Plan effective as of October 1, 2003.
12-36	Computation of Ratio of Earnings to Fixed Charges.
21-1	Subsidiaries of the Company.
23-18	Consent of Deloitte & Touche LLP.
31-21	Chief Executive Officer Section 302 Form 10-K Certification of Periodic Report.
31-22	Chief Financial Officer Section 302 Form 10-K Certification of Periodic Report.
(iii)	**Exhibits furnished herewith.**
32-21	Chief Executive Officer Section 906 Form 10-K Certification of Periodic Report.
32-22	Chief Financial Officer Section 906 Form 10-K Certification of Periodic Report.

EXHIBIT 10.60

SECOND AMENDMENT
TO THE
DTE ENERGY COMPANY EXECUTIVE SUPPLEMENTAL RETIREMENT PLAN

RECITALS

A. DTE Energy Company (the "Company") adopted the DTE Energy Company Executive Supplemental Retirement Plan (the "Plan") to enable the Company to attract and retain executives.

B. The Organization and Compensation Committee (the "Committee") of the Company's Board of Directors is authorized to amend the Plan.

C. By a resolution properly adopted on September 20, 2005, the Committee approved a revised Structure for Executive Pay and Benefits that requires amending the Plan.

D. By a resolution properly adopted on September 20, 2005, the Committee amended the Plan to implement the revised Structure.

PLAN AMENDMENT

Effective January 1, 2006, the DTE Energy Company Executive Supplemental Retirement Plan is amended as follows to implement the revised Structure for Executive Pay and Benefits:

1. Section 2.15 is replaced in its entirety with the following:

2.15 "COMPENSATION CREDIT" means:

(a) an amount equal to 10% of the Participant's Compensation for a Participant who is the DTE Chief Executive Officer, the DTE Chief Operating Officer, or in Executive Group 1 or 2;

(b) an amount equal to 9% of the Participant's Compensation for a Participant who is in Executive Group 3;

(c) an amount equal to 9% of the Participant's Compensation for a Participant who is in Executive Group 4 and who was a Participant as of December 31, 2005;

(d) an amount equal to 7% of the Participant's Compensation for a Participant who is in Executive Group 4 and who first became a Participant after December 31, 2005; and

(e) an amount equal to 5% of the Participant's Compensation for a Participant who is in Executive Group 5.

The credit will be computed and credited to the Participant's Account on a monthly basis as of the last business day of each month. In order to receive a Compensation Credit for a given month, the Participant must be actively employed by the Company or Affiliated Company on the last business day of that month.

2. New Section 2.17 A is added as follows:

2.17A "EXECUTIVE GROUP" is the grouping of executives to which a Participant is assigned by the Company for purposes of determining the Participant's compensation level, incentive targets, and executive benefit eligibility.

CERTIFICATE OF SECRETARY
OF
DTE ENERGY COMPANY

I, Sandra K. Ennis, certify that I am the Corporate Secretary of DTE Energy Company, a Michigan corporation (the "Company"), and have access to the Company's corporate records and am familiar with the matters contained and certified to in this Certificate.

I certify that, at a duly called meeting of the Organization and Compensation Committee (the "Committee") of the Board of Directors of the Company held on September 20, 2005, the Committee adopted the above resolutions and amendment.

/s/ Sandra K. Ennis

Sandra K. Ennis
Corporate Secretary

February 8,2006
Date

Exhibit 10.61

FIRST AMENDMENT TO THE
DTE ENERGY COMPANY EXECUTIVE DEFERRED COMPENSATION PLAN
(EFFECTIVE AS OF OCTOBER 1, 2003)

The First Amendment to the DTE Energy Company Executive Deferred Compensation Plan is adopted pursuant to resolutions approved by the DTE Energy Company Board of Directors on September 25, 2003.

1. Effective as of October 1, 2003, Section 2.07 "Cash Balance Plan" shall be amended and restated to read as follows:

> 2.07. Cash Balance Plan. "Cash Balance Plan" means any cash balance defined benefit plan maintained by the Company or an Affiliated Company which is intended to be qualified under Code section 401(a); provided, however, that the MCN Traditional Option and the DTE Traditional Option of the DTE Energy Company Retirement Plan shall be included in the definition of "Pension Plan," and not in the definition of "Cash Balance Plan".

2. Effective as of January 1, 2004, Section 2.08 "Cash Compensation" shall be amended and restated to read as follows:

> 2.08. Cash Compensation. "Cash Compensation" means Annual Cash Bonus or other cash payments (other than Performance Share Awards payable in cash, which are defined in Section 2.28 "Performance Share Awards") payable to a Participant.

3. Effective as of January 1, 2004, Section 2.14 "Contribution Subaccount" shall be amended and restated to read as follows:

> 2.14. Contribution Subaccount. "Contribution Subaccount" means a hypothetical bookkeeping record maintained by the Company to track the various allocations to a Participant's account. For purposes of this Plan, the balance in each Account shall be allocated among the Annual Cash Bonus Subaccount, the Base Salary Subaccount (for Base Salary deferred prior to January 1, 2004), the Prior Plans Subaccount, and the Mandatory Deferral Subaccount (collectively, known as the Contribution Subaccounts) as defined in Section 5 herein.

4. Effective as of October 1, 2003, Section 2.27 "Pension Plan" shall be amended and restated to read as follows:

> 2.27. Pension Plan. "Pension Plan" means any defined benefit plan maintained by the Company or an Affiliated Company, which is intended to be qualified under Code section 401(a). "Pension Plan"

> includes the MCN Traditional Option and the DTE Traditional Option of the DTE Energy Company Retirement Plan, but cash balance defined benefit plans shall otherwise be included in the definition of "Cash Balance Plan," and not in the definition of "Pension Plan."

5. Effective as of January 1, 2004, Section 4.02 "Deferral of Base Salary" shall be deleted in its entirety.

6. Effective as of January 1, 2004, Section 4.04 shall be amended and restated to read as follows:

> 4.04. Restoration of Qualified Plan Benefits. Amounts intended to

replace Qualified Plan benefits (but not earnings) under the Cash Balance Plan, the Pension Plan, or the Savings Plan which are reduced as a result of deferrals under Sections 4.01, 4.02, or 4.03 of this Plan will be restored through a Qualified Plan Make-up Subaccount in the DTE Energy Company Supplemental Retirement Plan.

7. Effective as of January 1, 2004, Subsections (a) through (c) of Section 4.04 "Restoration of Qualified Plan Benefits" shall be deleted in their entirety.

8. Effective October 1, 2003, Section 4.05 "Mandatory Deferral" shall be amended and restated to read as follows:

4.05. Mandatory Deferral. The Company may credit to the Participant's Mandatory Deferral Subaccount, on the date on which such compensation would otherwise have been payable, amounts which would have been nondeductible under Code section 162(m) on the date on which such compensation would otherwise be payable. The Deferral Period for the Mandatory Deferral Subaccount shall be through the date on which the Participant ceases to be a "covered employee" as that term is defined in Code section 162(m)(3). Any amounts in the Mandatory Deferral Subaccount shall be paid in the form of a lump sum.

9. Effective as of January 1, 2004, Section 5.01 "Establishment of Accounts" shall be amended and restated to read as follows:

5.01. Establishment of Accounts. The Committee shall establish a hypothetical bookkeeping Account for each Participant. Each Participant's Account shall be divided into one or more Contribution Subaccounts:

(a) For Participants deferring Base Salary prior to January 1, 2004, a "Base Salary Subaccount,"

(b) For Participants deferring Annual Cash Bonus, an "Annual Cash Bonus Subaccount,"

(c) For Participants who's Qualified Plan benefits are reduced because of their participation in this Plan, a "Qualified Plan Make-up Subaccount" in the DTE Energy Company Supplemental Retirement Plan,

(d) For Participants deferring Performance Share Awards payable in cash, a "Performance Share Subaccount,"

(e) For Participants whose compensation would otherwise be nondeductible under Code section 162(m), a "Mandatory Deferral Subaccount," and

(f) For Participants whose balance from a Prior Plan has been transferred to this Plan, a "Prior Plan Subaccount."

In addition, each Contribution Subaccount shall be divided into one or more Deferral Year Subaccounts, based on the Deferral Year of the contributions allocated to such Contribution Subaccount. The Prior Plan Subaccount shall be deemed to consist of one Deferral Year only.

10. Effective as of January 1, 2004, Subsection (a) of Section 5.02 "Contribution Subaccounts" shall be amended and restated to read as follows:

(a) Establishment of Contribution Subaccounts. A Participant's Contribution Subaccount shall be denominated on a monetary basis.

The Committee shall cause each separate Contribution Subaccount to be maintained in the name of each Participant with respect to whom all or a portion of Base Salary (prior to January 1, 2004), Annual Cash Bonus, or Performance Share Awards has been deferred, whose Qualified Plan benefits have been reduced because of his participation in this Plan, whose compensation has been mandatorily deferred because of Code section 162(m), or whose Prior Plan Balance has been transferred to this Plan.

11. Effective as of October 1, 2003, Subsection (b) of Section 6.01 "Distribution of Subaccounts" shall be amended and restated to read as follows:

(b) Timing of Distributions. A lump sum distribution shall be made as of March 1 following the end of the Deferral Period or, if earlier, March 1 following the end of the Plan Year in which the Participant's employment terminated for any reason other than death. If a Participant has elected to

receive his distribution in annual installments, the first installment shall be made as of March 1 following the end of the Deferral Period or, if earlier, March 1 following the end of the Plan Year in which the Participant's employment terminated for any reason other than death. All subsequent annual installments shall be made on approximately the same date each calendar year thereafter for the remainder of the distribution period. If no Deferral Election is on file with respect to the Deferral Year Subaccount or no distribution option is indicated on the Deferral Election, the Participant's Deferral Year Subaccount shall be distributed as of March 1 following the end of the Plan Year in which the Participant's employment is terminated for any reason other than death. Timing of a distribution due to a Participant's death shall be governed by Section 7.03.

12. Effective as of January 1, 2004, Section 6.03 "Change in Distribution Option" shall be amended and restated to read as follows:

6.03. Change in Distribution Option. A Participant may change the distribution option previously selected for a particular Deferral Year Subaccount at any time while actively employed by submitting a revised Deferral Election applicable to such Deferral Year Subaccount to the Committee. A change in time or manner of an in-service distribution must be made by the December 31 prior to the March 1 payment date, and if the timing of such distribution is changed, the new deferral period must be for at least two years.

13. Effective October 1, 2003, Section 6.04 "Hardship Withdrawals" shall be amended and restated to read as follows:

6.04. Hardship Withdrawals. An active Participant may request, in writing to the Vice President, Human Resources, a hardship withdrawal of all or part of his remaining Account which will be paid within 30 days in a single lump sum. Such distribution shall be made only if the Vice President, Human Resources determines that the Participant has an unforeseen emergency that constitutes a severe financial hardship to the Participant resulting from a sudden and unexpected illness or accident of the Participant or of a dependent (as defined in Code section 152(a)) of the Participant, loss of the Participant's property due to casualty, or other similar extraordinary and unforeseeable circumstances arising as a result of events beyond the control of the Participant. Payment may not be made to the extent that such hardship is or may be relieved through reimbursement or compensation by insurance or otherwise by liquidation of the Participant's assets, to the extent the liquidation of such assets would not itself cause severe financial hardship or by cessation of deferrals under the Plan. The distribution shall be limited to the amount required to meet the financial hardship. In making these determinations, the Vice President, Human Resources shall utilize the

regulations proposed or adopted under Code section 457. Hardship distributions shall be deducted from Contribution Subaccounts in the following order (i) the Annual Cash Bonus Subaccount; and (ii) the Base Salary Subaccount. Within each Contribution Subaccount, oldest Deferral Year Subaccounts will be depleted first. If a Participant elects a hardship withdrawal, any on-going deferral will cease, and the Participant may not again be designated as an Eligible Employee eligible to make additional deferrals under the Plan until the enrollment period occurring at the end of the Plan Year following the Plan Year in which the withdrawal was made.

14. Effective October 1, 2003, Section 6.05 "Unscheduled Withdrawals" shall be amended and restated to read as follows:

6.05. Unscheduled Withdrawals. Active Participants shall be permitted to make certain unscheduled withdrawals as described below:

(a) Election. Active Participants may request in writing to the Vice President, Human Resources an unscheduled withdrawal of the entire amount credited to the Participant's Account, including earnings, which will be paid within 30 days in a single lump sum.

(b) Withdrawal Penalty. There will be a penalty deducted from the Account prior to an Unscheduled Withdrawal equal to 10 percent of the Participant's Account. If a Participant elects such a withdrawal, any on-going deferral will cease, and the Participant may not again be designated as an Eligible Employee eligible to make additional deferrals under the Plan until the enrollment period occurring at the end of the Plan Year following the Plan Year in which the withdrawal was made.

This First Amendment to the DTE Energy Company Executive Deferred Compensation Plan is executed as September 25, 2003.

DTE ENERGY COMPANY

By: \s\ Larry E. Steward

Larry E. Steward
Vice President, Human Resources

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EXHIBIT 12-36

DTE ENERGY COMPANY
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

	Twelve Months Ended December 31				
	2005	2004	2003	2002	2001
(Millions of Dollars)					
Earnings:					
Pretax earnings....................	$ 497	$ 423	$ 287	$ 485	$ 202
Adjustments.....................	5	2	26	24	31
Fixed charges...................	547	544	569	557	476
Net earnings	$ 1,049	$ 969	$ 882	$ 1,066	$ 709
Fixed charges:					
Interest expense...................	$ 519	$ 516	$ 545	$ 553	$ 468
Adjustments.....................	28	28	24	4	8
Fixed charges	$ 547	$ 544	$ 569	$ 557	$ 476
Ratio of earnings to fixed charges	1.92	1.78	1.55	1.91	1.49

Exhibit 21-1

SUBSIDIARIES OF DTE ENERGY COMPANY

DTE Energy Company's principal subsidiaries as of December 31, 2005 are listed below. All other subsidiaries, if considered in the aggregate as a single subsidiary, would not constitute a significant subsidiary.

Subsidiary	State of Incorporation
1. The Detroit Edison Company	Michigan
2. DTE Enterprises, Inc.	Michigan
3. DTE Energy Resources, Inc.	Michigan
4. Michigan Consolidated Gas Company	Michigan

EXHIBIT 23-18

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference of our reports dated March 7, 2006, relating to the financial statements and financial statement schedule of DTE Energy Company (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the change in the methods of accounting for asset retirement obligations in 2005 and 2003 and energy trading contracts and gas inventories in 2003) and management's report on the effectiveness of internal control over financial reporting, appearing in the Annual Report on Form 10-K of DTE Energy Company for the year ended December 31, 2005, in the following registration statements:

Form	Registration Number
Form S-3	333-99955
Form S-3	333-74338
Form S-3	333-109591
Form S-3	333-113300
Form S-4	333-89175
Form S-8	333-61992
Form S-8	333-62192
Form S-8	333-00023
Form S-8	333-47247
Form S-8	333-109623

/S/ DELOITTE & TOUCHE LLP

Detroit, Michigan
March 7, 2006

Exhibit 31-21

FORM 10-K CERTIFICATION

I, Anthony F. Earley, Jr., certify that:

1. I have reviewed this annual report on Form 10-K of DTE Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ ANTHONY F. EARLEY, JR. Date: March 7, 2006

Anthony F. Earley, Jr.
Chairman of the Board
and Chief Executive Officer of DTE Energy Company

FORM 10-K CERTIFICATION

I, David E. Meador, certify that:

1. I have reviewed this annual report on Form 10-K of DTE Energy Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ DAVID E. MEADOR Date: March 7, 2006

David E. Meador
Executive Vice President and
Chief Financial Officer of DTE Energy Company

Exhibit 32-21

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K of DTE Energy Company (the “Company”) for the year ended December 31, 2005, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Anthony F. Earley, Jr., certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge and belief:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 7, 2006

/s/ ANTHONY F. EARLEY, JR.

Anthony F. Earley, Jr.
Chairman of the Board and Chief Executive
Officer of DTE Energy Company

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32-22

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K of DTE Energy Company (the “Company”) for the year ended December 31, 2005, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, David E. Meador, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge and belief:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 7, 2006

/s/ DAVID E. MEADOR
David E. Meador
Executive Vice President and Chief Financial
Officer of DTE Energy Company

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.