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 ACT 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, 2006

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 Stock Exchange
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, 2006, the aggregate market value of the Registrant's voting and non-voting common equity held by non-affiliates was approximately $7.2 billion (based on the New York Stock Exchange closing price on such date). There were 177,123,754 shares of common stock outstanding at January 31, 2007.

Certain information in DTE Energy Company's definitive Proxy Statement for its 2007 Annual Meeting of Common Shareholders to be held May 3, 2007, 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, 2006

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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
CTA	Costs to achieve, consisting of project management, consultant support and employee severance, related to the Performance Excellence Process
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)
MDEQ	Michigan Department of Environmental Quality
MichCon	Michigan Consolidated Gas Company (an indirect wholly owned subsidiary of DTE Energy) and subsidiary companies
MISO	Midwest Independent System Operator, a Regional Transmission Organization
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 Sections 45K and 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.
Subsidiaries	The direct and indirect subsidiaries of DTE Energy Company
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 or the potential requirement to refund proceeds received from synfuel partners;
- 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, including any associated impact on rate structures;
- contributions to earnings by non-utility subsidiaries;
- changes in and application of 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 and application of 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;
- binding arbitration, litigation and related appeals;
- 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; and
- timing, terms and proceeds from any asset sale or monetization.

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.

Part I

Items 1. and 2. Business 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 five non-utility segments that are engaged in a variety of energy related businesses. In August 2005, the Energy Policy Act of 2005 repealed the Public Utility Holding Company Act of 1935 (PUHCA), effective February 8, 2006. 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," "Company" or "DTE" are to DTE Energy and its subsidiaries, collectively.

Corporate Structure

In the third quarter of 2006, we realigned the non-utility segment Power and Industrial Projects business unit to separately present the Synthetic Fuel business. The impending expiration of synfuel tax credits as of December 31, 2007, combined with the sustained volatility of oil prices, increased management focus on synfuels, thereby requiring a separate business segment. In the fourth quarter of 2006, we separated the Fuel Transportation and Marketing segment into Coal and Gas Midstream, and Energy Trading corresponding to additional management focus on the results of these non-utility segments. Based on the following structure, we set strategic goals, allocate resources and evaluate performance. See Note 18 of the Notes to Consolidated Financial Statements for financial information by segment for the last three years.

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

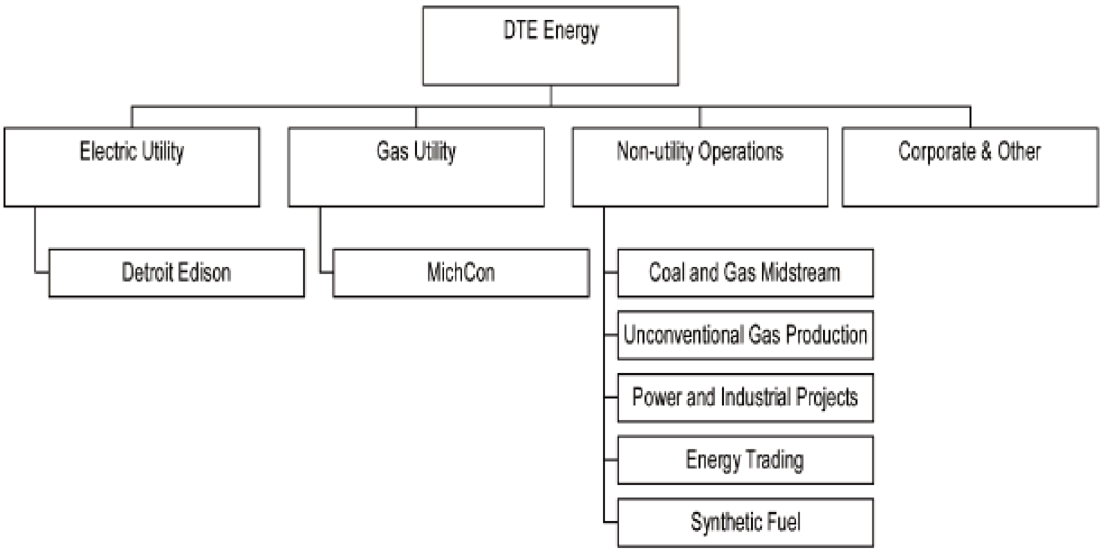
- Consists of the gas distribution services provided by MichCon, a gas utility that purchases, stores and distributes natural gas throughout Michigan to approximately 1.3 million residential, commercial and industrial customers and Citizens Gas Fuel Company (Citizens), a gas utility that distributes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

Non-Utility Operations

- *Coal and Gas Midstream*, primarily consisting of coal transportation and marketing, and gas pipelines, processing and storage;

- *Unconventional Gas Production,* primarily consisting of unconventional gas project development and production;
- *Power and Industrial Projects*, primarily consisting of on-site energy services, steel-related projects and power generation with services;
- *Energy Trading,* primarily consisting of energy marketing and trading operations; and
- *Synthetic Fuel,* consisting of the operations of nine synfuel plants.

Corporate & Other, primarily consisting of corporate staff 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, but not limited to, 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)	2006	2005	2004
Residential	**$ 1,671**	$ 1,517	$ 1,345
Commercial	**1,603**	1,331	1,123
Industrial	**835**	697	557
Wholesale	**109**	73	65
Other	**350**	464	234
Subtotal	**4,568**	4,082	3,324
Interconnection sales (1)	**169**	380	244
Total Revenue	**$ 4,737**	$ 4,462	$ 3,568

(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 to have 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 six long-term and two short-term contracts for a total purchase of approximately 35 million tons of low-sulfur western coal to be delivered from 2007 to 2010. We also have ten contracts for the purchase of approximately 8 million tons of Appalachian coal to be delivered from 2007 through 2009. All of these contracts have fixed prices. We have approximately 90% of our 2007 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 MISO. 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.

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, 2006 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 8.

(4) The Monroe Power Plant provided 38% of Detroit Edison's total 2006 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 8.

Detroit Edison owns and operates 675 distribution substations with a capacity of approximately 33,075,000 kilovolt-amperes (kVA) and approximately 426,700 line transformers with a capacity of approximately 25,883,000 kVA.

Circuit miles of distribution lines owned and in service as of December 31, 2006 are as follows:

Electric Distribution Operating Voltage-Kilovolts (kV)	Circuit Miles Overhead	Underground
4.8 kV to 13.2 kV	28,155	13,747
24 kV	101	690
40 kV	2,323	332
120 kV	70	13
	30,649	14,782

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 Transmission and connect to neighboring energy companies.

Regulation

Detroit Edison's business is subject to the regulatory jurisdiction of various agencies, including, but not limited to, 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 customers 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.

In March 2006, the MPSC issued an order directing Detroit Edison to show cause by June 1, 2006 why its retail electric rates should not be reduced in 2007. The MPSC cited certain changes that had occurred since the November 2004 order in Detroit Edison's last general rate case, or were expected to occur. These changes included: declines in electric Customer Choice program participation, expiration of the residential rate caps, and projected reductions in Detroit Edison operating costs. The show cause filing was to reflect sales, costs and financial conditions that were expected to occur by 2007. On June 1, 2006, Detroit Edison filed its response explaining why its electric rates should not be reduced in 2007. Detroit Edison indicated that it will have a revenue deficiency of approximately $45 million beginning in 2007 due to significant capital investments over the next several years for infrastructure improvements to enhance electric service reliability and for mandated environmental expenditures. The impacts of these investments will be partially offset by efficiency and cost-savings measures that have been initiated. Therefore, Detroit Edison requested that the show cause proceeding allow for rate increase adjustments based on the combined effects of investment expenditures and cost-savings programs. The MPSC denied this request and indicated that a full review of rates will be made in Detroit Edison's next general rate case, which is due to be filed by July 1, 2007. The MPSC issued an order approving a settlement agreement in this proceeding on August 31, 2006. The order provided for an annualized rate reduction of $53 million for 2006, effective September 5, 2006. Beginning January 1, 2007, and continuing until the later of March 31, 2008 or 12 months from the filing date of Detroit Edison's next main case, rates will be reduced by an additional $26 million, for a total reduction of $79 million. The revenue reduction is net of the recovery of the amortization of the costs associated with the implementation of the Performance Excellence Process, a company wide review of our operations. The settlement agreement provides for some level of realignment of the existing rate structure by allocating a larger percentage share of the rate reduction to the commercial and industrial customer classes than to the residential customer classes. As part of the settlement agreement, a Choice Incentive Mechanism (CIM) was established with a base level of electric choice sales set at 3,400 GWh.

In accordance with the MPSC's directive 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. In September 2006, the MPSC issued an order recognizing $19 million of 2004 net stranded costs that required Detroit Edison to write off $112 million of 2004 net stranded costs. The MPSC order resulted in a $39 million reduction in the 2004 PSCR over-collection by allowing Detroit Edison to retain the benefit of third party wholesale sales required to support the electric Customer Choice program and to offset the recognition of the $19 million of 2004 stranded costs. The MPSC order also resulted in reductions to accrued interest on the 2004 and 2005 PSCR amounts of $15 million. The MPSC directed Detroit Edison to include the remaining 2004 PSCR over-collection amount and related interest in the 2005 PSCR Reconciliation which is in an under-collected position. The order resulted in a reduction of pre-tax income of approximately $58 million.

See Note 6 of the Notes to Consolidated Financial Statements.

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 6% of retail sales in 2006, 12% in 2005 and 18% of such sales in 2004 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 Transmission. By FERC order, rates charged by ITC Transmission 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.

We are currently involved in a contract dispute with BNSF Railway Company that has been referred to arbitration. Under this contract, BNSF transports western coal east for Detroit Edison and the Coal Transportation and Marketing business. We have filed a breach of contract claim against BNSF for the failure to provide certain services that we believe are required by the contract. The arbitration hearing is scheduled for mid-2007. While we believe we will prevail on the merits in this matter, a negative decision with respect to the significant issues being heard in the arbitration could have an adverse effect on our business.

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 to approximately 17,000 customers.

Revenue is generated by providing the following major classes of service: gas sales, end user transportation, intermediate transportation and gas storage.

Revenue by Service

(in Millions)	**2006**	2005	2004
Gas sales	**$ 1,541**	$ 1,860	$ 1,435
End user transportation	**135**	134	119
Intermediate transportation	**69**	58	56
Other	**104**	86	72
Total Revenue	**$ 1,849**	$ 2,138	$ 1,682

- *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 gas storage, providing appliance maintenance, facility development 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 71% of the volume coming from underground storage for 2006. Peak-use requirements are met through utilization of our storage facilities, pipeline transportation capacity, and purchased gas supplies. 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 NYMEX and 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 19,000 miles of distribution mains, approximately 1,188,000 service lines and approximately 1,321,000 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. In addition, we sell storage services to third parties. 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 13 of the Notes to Consolidated Financial Statements.

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 6 of the Notes to the Consolidated Financial Statements.

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 be a 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 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 for end user transportation 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 storage capacity.

Our extensive transmission pipeline system has enabled us to market 500 to 600 Bcf annually 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 Canada.

NON-UTILITY OPERATIONS

Coal and Gas Midstream

Description

Coal and Gas Midstream primarily consists of the operations of Coal Transportation and Marketing, and the Pipelines, Processing and Storage businesses.

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)	2006	2005	2004
Tons of Coal Shipped (1)	**34**	42	40

(1) Includes intercompany transactions of 14 tons, 20 tons, and 18 tons in 2006, 2005, and 2004, respectively.

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. We specialize in providing natural gas storage and transportation services in the Midwest and Northeast. We have interests in six processing plants that extract carbon dioxide from Antrim gas production in northern Michigan, making it suitable for transportation to nearby customers. Additionally, we have storage capacity 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 hubs.

Properties

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	100%	66 Bcf of storage capacity	Washington Twp, MI

The assets of these businesses are complementary with other DTE Energy assets. Pursuant to an operating agreement, MichCon provides physical operations, maintenance and technical support for the Washington 28 and Washington 10 storage facilities.

Strategy and Competition

Our Coal Transportation and Marketing business is one of the leading North American coal marketers. We have a reputation as being 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. We will seek to build our capacity to transport greater amounts of western coal and to expand into coal terminals. We are currently involved in a contract dispute with BNSF Railway Company that has been referred to arbitration. Under this contract, BNSF transports western coal east for Detroit Edison and the Coal Transportation and Marketing business. We have filed a breach of contract claim against BNSF for the failure to provide certain services that we believe are required by the contract. The arbitration hearing is scheduled for mid-2007. While we believe we will prevail on the merits in this matter, a negative decision with respect to the significant issues being heard in the arbitration could have an adverse effect on our ability to grow the Coal Transportation and Marketing business as currently contemplated.

The Pipelines, Processing and Storage business 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 facilities. Vector received FERC approval in October 2006 for a 200 MMcf per day expansion of long-haul capacity scheduled to be in service by November 2007. In April 2006, the Washington 10 storage facility expanded working capacity from 51.4 to 66 Bcf. In October 2006, we purchased the lessor interest in the 66 Bcf Washington 10 gas storage field. Prior to the purchase, we leased the storage rights. Another opportunity is Millennium Pipeline in New York, in which we have a 26.25% interest. In December 2006, Millennium Pipeline received FERC approval for construction and operation and is expected to be in service in late 2008. The Millennium Pipeline will be able to transport up to 525 MMcf per day. The gas supply for Millennium could be sourced from Michigan storage facilities or from Vector Pipeline for consumption in the Northeast U.S.

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 Texas. We are an experienced operator in the Antrim shale where we manage one of the industry's largest inventories of proved gas shale reserves. We continue to develop properties in both areas as we explore monetization alternatives.

During 2006, we invested $186 million acquiring, testing, developing and producing our Antrim and Barnett shale acreage. In 2006, we added proved reserves of 219 Bcfe in both the Antrim and Barnett shales, resulting in year end total proved reserves of 616 Bcfe. The Barnett and Antrim shale wells yielded 4.1 Bcfe and 21.5 Bcfe of production, respectively, in 2006 for a total of 25.6 Bcfe. Barnett shale leasehold acres increased to 89,808 gross acres (80,530 net of interest of others) after reduction by opportunistic sales of 11,193 acres. We drilled a total of 206 development wells (165.2 net of interest of others) including 64 wells (54.8 net of interest of others) in the Barnett shale acreage with a success rate of 100% in 2006. Included were 4 test wells (3.2 net of interest of others) in unproved areas of the southern portion of our Barnett shale acreage holdings. Production commenced in the Bosque and Hill Counties of Texas in 2006. Testing of Barnett's southern acreage is ongoing and will continue in 2007.

Properties

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

	2006		2005		2004	
	Gross	**Net**(1)	Gross	Net(1)	Gross	Net (1)
Producing Wells and Acreage						
Producing Wells (2)						
Antrim shale	**2,148**	**1,700**	2,010	1,630	1,878	1,523
Barnett shale	**123**	**110**	65	55	5	1
	2,271	**1,810**	2,075	1,685	1,883	1,524
Developed Lease Acreage (3)						
Antrim shale	**283,007**	**228,232**	278,789	217,643	266,064	213,959
Barnett shale	**17,965**	**16,045**	15,524	14,367	1,262	316
	300,972	**244,277**	294,313	232,010	267,326	214,275
Undeveloped Lease Acreage (4)						
Antrim shale	**80,380**	**66,184**	86,028	73,056	92,328	79,025
Barnett shale	**71,842**	**64,485**	72,280	61,627	54,530	48,541
	152,222	**130,669**	158,308	134,683	146,858	127,566

(1) Excludes the interest of others.

(2) Producing wells is the number of wells that are found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

(3) Developed lease acreage is the number of acres that are allocated or assignable to productive wells or wells capable of production.

(4) Undeveloped lease acreage is the number of acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil regardless of whether such acreage contains proved reserves.

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. A long-term fixed price obligation that fixed the price of gas sold at $3.33 for 1.8 Bcf of Antrim shale production expired in 2006. This creates pricing opportunities and we have and will continue to remarket Antrim shale gas production at current higher market rates.

Additional long-term fixed price obligation data for the next five years follows:

	2007	2008	2009	2010	2011
Long-term fixed price obligations					
Antrim					
Volume- Bcf	**17.6**	16.2	15.0	15.0	11.9
Price- $/Mcf	**$3.19**	$ 3.74	$ 3.48	$3.59	$ 3.70
Barnett					
Volume- Bcf	**1.8**	1.3	1.1	0.5	—
Price- $/Mcf	**$ 8.45**	$8.15	$7.73	$7.29	$ —

Current natural gas prices and 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 2007, we expect to drill 130 to 145 wells in the Antrim shale and 50 to 55 wells in the Barnett shale. Combined investment for both areas is expected to be approximately $150 million to $170 million during 2007. Successful testing on unproved acreage may yield additional significant investment opportunities.

We are exploring the sale of a portion of our Unconventional Gas Production assets which will allow us to monetize value from our more mature holdings, while retaining the ability to benefit from the upside of our earlier stage holdings.

Power and Industrial Projects

Description

Power and Industrial Projects is comprised primarily of projects that deliver utility-type services to industrial, commercial and institutional customers, and biomass energy projects. We provided utility-type services using project assets usually located on the customers' premises in the steel, automotive, pulp and paper, airport and other industries. These services include pulverized coal and petroleum coke supply, power generation, steam production, chilled water production, wastewater treatment and compressed air supply. We own and operate three gas-fired peaking electric generating plants and a biomass-fired electric generating plant and operate one additional gas-fired power plant under contract. Additionally, we own a gas-fired peaking electric generating plant that was taken out of service in September 2006. We develop, own and operate landfill gas recovery systems throughout the United States. We produce metallurgical coke from two coke batteries. The production of coke from our coke batteries generates production tax credits (assuming no phase-out).

Properties

The following are significant Power and Industrial Projects:

Facility	Location	% Owned	Service Type
Steel			
PCI Enterprises, Inc.	River Rouge, MI	100%	Pulverized Coal
DTE Sparrows Point	Sparrows Point, MD	100%	Pulverized Coal
EES Coke Battery, LLC	River Rouge, MI	100%	Metallurgical Coke Supply
Indiana Harbor Coke Co., LP	East Chicago, IN	5%	Metallurgical Coke Supply
Automotive			
DTE Energy Center	Various sites in MI, IN, OH	50%	Electric Distribution, Chiller Water, Waste Water, Compressed Air, Mist and Dust Collectors
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
Defiance Energy	Defiance, OH	100%	Steam, Cooling Tower Water, Chilled Water, Compressed Air
Heritage	Dearborn, MI	100%	Electric Distribution
Lordstown Energy	Lordstown, OH	100%	Steam, Chilled Water, Compressed Air and Reverse Osmosis Water
Pulp and Paper			
Mobile Energy Services	Mobile, AL	50%	Electric Generation and Steam
Tembec	St. Francisville, LA	100%	Electric Generation and Steam
Airport			
Metro Energy	Romulus, MI	100%	Electricity, Hot and Chilled Water
Pittsburgh	Pittsburg, PA	100%	Hot and Chilled Water
Other Industries			
DTE PetCoke	Vicksburg, MS	100%	Pulverized Petroleum Coke

Pursuant to an operating agreement with PCI Enterprises, Inc., Detroit Edison provides operations and maintenance services for the pulverized coal facility located at Detroit Edison's River Rouge power plant.

Production tax credits, related to one coke battery that expired in 2002, were reinstated for the years 2006 through 2009. The coke battery facilities produce coke that is used in blast furnaces within the steel industry.

(Dollars in Millions)	2006	2005	2004
Production Tax Credits Generated			
Coke Batteries:			
Allocated to DTE Energy	**$ 6**	$ 2	$ 2

Non-Utility Power Generation

Description

We operate peaking, gas-fired and biomass-fired electric generating plants.

Properties

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 (1)	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

(1) No longer in service effective September 2006.

Production tax credits are available at one Non-Utility Power Generation facility. The facility produces electricity using renewable resources.

(Dollars in Millions)	2006	2005	2004
Production Tax Credits Generated			
Allocated to DTE Energy	**$ 1**	$ —	$ —

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 provide local utilities, industry and consumers with an opportunity to use a competitive, renewable source of energy, in addition to providing environmental benefits by reducing greenhouse gas emissions. We also co-own, with the Coal Transportation and Marketing segment, a coal mine methane gathering system and gas processing facility in southern Illinois. This processed methane is sold into the natural gas transmission system. Many of our facilities generate production tax credits that will expire at the end of 2007.

Landfill gas recovery has operations in 12 states.

(Dollars in Millions)	2006	2005	2004
Landfill Sites	**26**	32	29
Gas Produced (in Bcf)	**22.9**	20.2	23.2
Tax Credits Generated (1)	**$ 5**	$ 8	$ 8

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

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 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:

- Providing operating services to owners of industrial and power plants;
- Acquiring and developing solid fuel-fired power plants and landfill gas recovery facilities; and
- Expanding energy projects.

We are exploring the combination of a sale of an equity interest in, and recapitalization of, some of the assets of the Power and Industrial Projects business, including the sale or restructuring of the power generation assets. In February 2007, we entered into an agreement to sell our Georgetown peaking electric generating facility. The sale is subject to receipt of regulatory approval and is expected to close in the second half of 2007.

Energy Trading

Description

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. Energy Trading provides commodity risk management services to the other businesses within DTE Energy.

Strategy and Competition

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. We are exploring strategic options for the energy trading business.

Synthetic Fuel

Description

Synfuel plants chemically change coal and waste coal into a synthetic fuel as determined under the Internal Revenue Code. 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. Production tax credits are provided for the production and sale of solid synthetic fuel produced from coal and are available through December 31, 2007. The synthetic fuel plants generate operating losses which we expect to be offset by production tax credits. The value of a production tax credit is adjusted annually by an inflation factor and published annually by the Internal Revenue Service (IRS) and is reduced, or eliminated, if the Reference Price of a barrel of oil exceeds certain thresholds.

We are the operator of nine synthetic fuel production facilities throughout the United States. On May 12, 2006, we idled production at all nine of the synthetic fuel facilities. The decision to idle synfuel production was driven by the level and volatility of oil prices at that time. During the idle period, we took various steps to reduce our oil price exposure, including, renegotiation of a significant number of commercial agreements. Beginning September 5, 2006 through October 4, 2006, we resumed production at each of the nine synfuel facilities due to these amended commercial agreements and declines in the level of oil prices.

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 consolidate these projects due to our controlling influence and continuing involvement.

(Dollars in Millions)	**2006**	2005	2004
Production Tax Credits Generated			
Synfuel Plants			
Allocated to DTE Energy	**$ 23**	$ 45	$ 29
Allocated to partners	**260**	562	411
	$ 283	$ 607	$ 440

Properties

The following are our synthetic fuels projects:

Facility	Location	% Owned	Industry Served
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	Clover, VA	51%	Utility
DTE Buckeye, LLC (2 plants)	Cheshire, OH	1%	Utility

Strategy and Competition

Due to our hedging strategy implemented in 2006, we expect to continue to operate the synfuel plants through December 31, 2007, when synfuel-related production tax credits expire.

CORPORATE & OTHER

Description

Corporate & Other includes various corporate staff functions. Because these functions 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 companies and funds.

Strategy and Competition

Our energy-related investment strategy is to create a profitable portfolio by investing in companies or funds that facilitate the creation of new businesses, expand growth opportunities for existing businesses or enable performance improvements in our existing businesses.

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 estimated significant future environmental expenditures:

(in Millions)	Electric	Gas	Non- Utility	Total
Air	$ 2,185	$ —	$ —	$ 2,185
Water	53	—	14	67
MGP Sites	4	41	—	45
Other Clean Up Sites	12	1	—	13
Estimated total future expenditures	$ 2,254	$ 42	$ 14	$ 2,310
Estimated 2007 expenditures	$ 234	$ 5	$ 14	$ 253

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 – In response to an EPA regulation, 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 one to two years, Detroit Edison may be required to perform some mitigation activities, including, the possible installation of additional control technologies to reduce the environmental impact of the intake structures. However, a recent court decision remanded back to the EPA several provisions of the federal regulation resulting in a delay in complying with the regulation.

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. In addition, Detroit Edison will be making capital improvements to the ash landfill in 2007.

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 facility in Michigan. We expect the project to be completed within one year. Our non-utility affiliates are substantially in compliance with all environmental requirements.

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

Note	Title
6	Regulatory Matters
7	Nuclear Operations

EMPLOYEES

The following table shows our employees as of December 31, 2006:

	Represented	Non-represented	Total
Detroit Edison	3,724	3,493	7,217
MichCon	1,386	707	2,093
Other	308	909	1,217
Total	5,418	5,109	10,527

There are several bargaining units for our represented employees. Approximately 3,245 of our represented employees are under contracts that expire in June 2007 and 970 employees are under contracts that expire in October 2007. The contracts of the remaining represented employees expire at various dates in 2008 and 2009.

EXECUTIVE OFFICERS OF DTE ENERGY

Name	Age (1)	Present Position	Present Position Held Since
Anthony F. Earley, Jr.	57	Chairman of the Board and Chief Executive Officer	8-1-98
Gerard M. Anderson	48	Chief Operating Officer and	10-31-05
		President	6-23-04
Stephen E. Ewing (2)	62	Vice Chairman, DTE Energy	10-31-05
		President and Chief Operating Officer, MichCon	4-28-05
Robert J. Buckler	57	President and Chief Operating Officer, Detroit Edison	10-31-05
		Group President, DTE Energy	5-31-05
David E. Meador	49	Executive Vice President and Chief Financial Officer	6-23-04
Lynne Ellyn	55	Senior Vice President and Chief Information Officer	12-31-01
Paul C. Hillegonds	57	Senior Vice President	5-16-05
Ron A. May	55	Senior Vice President	1-22-04
Bruce D. Peterson	50	Senior Vice President and General Counsel	6-25-02
Gerardo Norcia	44	Executive Vice President, MichCon	10-31-05
Larry E. Steward	54	Vice President	1-15-01
Peter B. Oleksiak	40	Vice President and Controller	12-5-05
Sandra K. Ennis	50	Corporate Secretary	8-4-05

(1) As of December 31, 2006

(2) Retired from the company effective December 31, 2006

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. Hillegonds, Peterson and

Norcia, all of the above officers have been employed by DTE Energy in one or more management capacities during the past 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.

Gerardo Norcia was elected Executive Vice President, MichCon on October 31, 2005. Mr. Norcia was President, DTE Gas Storage, Pipelines and Processing since joining DTE Energy on November 4, 2002. He was a vice president of Union Gas prior to joining DTE Energy.

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 eight insurance policies providing aggregate coverage in the amount of $185 million.

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. 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. We have generated production tax credits from the synfuel, coke battery, landfill gas recovery and gas production operations. We have received favorable private letter rulings on all of the synfuel facilities. All production tax credits taken after 2003 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 potential legislation. Moreover, the opportunity to earn additional production tax credits related to the generation of synfuels and recovery of landfill gas will 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 potential 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 the synfuel facilities.

This incentive provided by production tax credits is not deemed necessary if the price of oil increases and provides significant market incentives for the production of 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. We project the yearly average wellhead price per barrel of oil for the year to be 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 $55 per barrel and would be completely phased out if the Reference Price reached $69 per barrel. As of December 31, 2006, the average NYMEX daily closing price of a barrel of oil was approximately $66 for 2006, equating to an estimated Reference Price of $60, which we estimate to be within the phase-out range. To mitigate the effect of a potential phase out and minimize operating losses, on May 12, 2006 we idled production at all nine of the synfuel facilities. The decision to idle synfuel production was driven by the level and volatility of oil prices at that time. Beginning September 5, 2006 through October 4, 2006, we resumed production at each of the nine synfuel facilities due to declines in the level of oil prices.

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.

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 State of Michigan currently experiences a hybrid market, where the MPSC continues to regulate electric rates for our customers, while alternative electric suppliers 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 implementation period of electric Customer Choice, many commercial customers chose alternative electric suppliers. Recent MPSC rate orders 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. The hybrid market in Michigan also causes uncertainity as it relates to investment in new generating capacity.

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.

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.

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 our non-utility businesses that compete with utilities and alternative electric suppliers.

A work interruption may adversely affect us. Unions represent approximately 5,400 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.

Michigan tax reform may be costly. The State of Michigan is experiencing a revenue shortfall. We are a significant taxpayer in the State of Michigan. The legislature is expected to change the tax laws in 2007, and 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 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.

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. We are in the midst of a multi-year Company-wide initiative to improve existing processes and implement new core information systems. We launched the first phase of our Enterprise Business Systems 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.

Benefits of the Performance Excellence Process to the Company could be less than the Company has projected. In 2005, we initiated a company-wide review of our operations called the Performance Excellence Process with the overarching goal to become more competitive by reducing costs, eliminating waste and optimizing business processes while improving customer service. Actual results achieved through this process could be less than the Company's expectations.

The inability to consummate any strategic transactions for our non-utility operations could affect our expected cash flows. As part of a strategic review of our non-utility operations, we are considering various actions including the sale, restructuring or recapitalization of various non-utility businesses. If we are not able to consummate any strategic transactions on favorable terms or timing, our expected cash flows could be lower than anticipated.

Item 1B. Unresolved Staff Comments

None.

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.

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

Note	Title
6	Regulatory Matters
7	Nuclear Operations
15	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 2006.

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. 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:

Year	Quarter	High	Low	Dividends Paid Per Share
2006	**First**	**$ 44.23**	**$ 40.00**	**$ 0.515**
	Second	**$ 41.91**	**$38.77**	**$ 0.515**
	Third	**$ 43.63**	**$ 40.26**	**$ 0.515**
	Fourth	**$ 49.24**	**$41.37**	**$ 0.530**
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

At December 31, 2006, there were 177,138,060 shares of our common stock outstanding. These shares were held by a total of 89,984 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 10 of the Notes to Consolidated Financial Statements for information concerning the Shareholders' Rights Agreement.

We paid cash dividends on our common stock of $365 million in 2006, $360 million in 2005, and $354 million in 2004. 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 for the foreseeable future. In fourth quarter of 2006, we announced a quarterly dividend increase, effective January 15, 2007, from $0.515 per share to $0.53 per share.

All of our equity compensation plans that provide for the annual awarding of stock-based compensation have been approved by shareholders. See Note 17 of the Notes to Consolidated Financial Statements for additional detail.

See the following table for information as of December 31, 2006.

	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	5,667,197	$ 41.60	7,654,802

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, 2006:

Period	Total Number of Shares Purchased (1)	Average Price Paid Per Share (1)	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (2)	Average Price Paid Per Share (2)	Maximum Dollar Value that May Yet Be Purchased Under the Plans or Programs (2)
01/01/06 — 01/31/06	—	—	—		$ 700,000,000
02/01/06 — 02/28/06	—	—	—		700,000,000
03/01/06 — 03/31/06	199,555	42.70	—		700,000,000
04/01/06 — 04/30/06	37,525	40.65	—		700,000,000
05/01/06 — 05/31/06	—	—	—		700,000,000
06/01/06 — 06/30/06	6,725	41.13	—		700,000,000
07/01/06 — 07/31/06	1,000	40.83	—		700,000,000
08/01/06 — 08/31/06	—	—	—		700,000,000
09/01/06 — 09/30/06	1,500	40.71	—		700,000,000
10/01/06 — 10/31/06	—	—	—		700,000,000
11/01/06 — 11/30/06	—	—	—		700,000,000
12/01/06 — 12/31/06	36,250	49.10	1,000,000	48.47	651,506,040
Total	282,555	43.19	1,000,000		

(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 repurchases from time to time, and will depend on future asset monetizations, cash flows and other investment opportunities.

Item 6. Selected Financial Data

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

(in Millions, except per share amounts)	2006	2005	2004	2003	2002
Operating Revenues	**$ 9,022**	$ 9,021	$ 7,069	$ 6,999	$ 6,680
Net Income (Loss)					
Total from continuing operations	**$ 437**	$ 577	$ 464	$ 475	$ 598
Discontinued operations	**(5)**	(37)	(33)	73	34
Cumulative effect of accounting changes	**1**	(3)	—	(27)	—
Net Income	**$ 433**	$ 537	$ 431	$ 521	$ 632
Diluted Earnings Per Share					
Total from continuing operations	**$ 2.45**	$ 3.28	$ 2.68	$ 2.83	$ 3.62
Discontinued operations	**(.03)**	(.21)	(.19)	.42	.21
Cumulative effect of accounting changes	**.01**	(.02)	—	(.16)	—
Diluted Earnings Per Share	**$ 2.43**	$ 3.05	$ 2.49	$ 3.09	$ 3.83
Financial Information					
Dividends declared per share of common stock	**$ 2.075**	$ 2.06	$ 2.06	$ 2.06	$ 2.06
Total assets	**$ 23,785**	$ 23,335	$21,297	$ 20,753	$19,985
Long-term debt, including capital leases	**$ 7,474**	$ 7,080	$ 7,606	$ 7,669	$ 7,803
Shareholders' equity	**$ 5,849**	$ 5,769	$ 5,548	$ 5,287	$ 4,565

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

OVERVIEW

DTE Energy is a diversified energy company with 2006 revenues in excess of $9 billion and approximately $24 billion in assets. 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, distribution and storage services throughout southeastern Michigan. We operate five energy-related non-utility segments with operations throughout the United States.

The following table summarizes our financial results:

(in Millions, except Earnings per Share)	2006	2005	2004
Income from Continuing Operations	**$ 437**	$ 577	$ 464
Earnings per Diluted share	**$2.45**	$3.28	$2.68
Net Income	**$ 433**	$ 537	$ 431
Earnings per Diluted Share	**$2.43**	$3.05	$2.49

The decrease in 2006 net income is primarily due to the temporary idling of synfuel plants along with the associated impairments and reserves, and impairments within our Power and Industrial Projects segment. This decrease was partially offset by higher earnings at our electric utility, Detroit Edison, and Energy Trading segment mark-to-market losses in 2005 which did not recur in 2006.

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

- Effects of weather and collectibility of accounts receivable on utility operations;
- Impact of regulatory decisions on our utility operations;
- Investments in our Unconventional Gas Production business;
- Results in our Energy Trading business;
- Synfuel-related earnings and the impact of temporarily idling synfuel facilities in 2006; and
- Cost reduction efforts and required capital investment.

UTILITY OPERATIONS

Weather - Earnings from our utility operations are seasonal and very sensitive to weather. Electric utility earnings are primarily dependent on hot summer weather, while the gas utility's results are primarily dependent on cold winter weather. During 2006, we experienced milder than normal weather conditions.

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 $46 million in 2006, $82 million in 2005 and $48 million in 2004.

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, higher natural gas prices and a 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 2006, we sold previously written-off accounts of $43 million resulting in a gain and net proceeds of $1.9 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 increased to $123 million in 2006 from $98 million in 2005 and from $105 million in 2004.

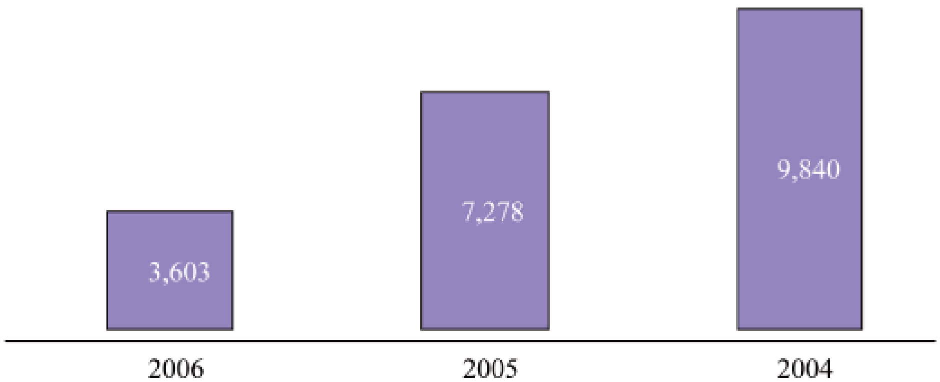
The April 2005 MPSC gas rate order provided for an uncollectible true-up mechanism for MichCon. We filed the 2005 annual reconciliation, comparing our actual uncollectible expense to our designated revenue recovery of approximately $37 million on an annual basis. The MPSC approved the 2005 annual reconciliation on December 21, 2006 allowing MichCon to surcharge the $11 million excess beginning in January 2007.

We expect to file the 2006 annual reconciliation with the MPSC no later than March 31, 2007 comparing our actual 2006 uncollectible expense to our designated revenue recovery of approximately $37 million. Ninety percent of the difference for the year will be requested to be surcharged as part of the annual reconciliation proceeding before the MPSC. We have accrued $33 million under the 2006 uncollectible true-up mechanism.

Regulatory activity - In accordance with the MPSC's directive 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. In September 2006, the MPSC issued an order recognizing $19 million of 2004 net stranded costs that required Detroit Edison to write off $112 million of 2004 net stranded costs. The MPSC order resulted in a $39 million reduction in the 2004 PSCR over-collection by allowing Detroit Edison to retain the benefit of third party wholesale sales required to support the electric Customer Choice program and to offset the recognition of the $19 million of 2004 stranded costs. The MPSC order also resulted in reductions in accrued interest on the 2004 and 2005 PSCR amounts of $15 million. The MPSC directed Detroit Edison to include the remaining 2004 PSCR over-collection amount and related interest in the 2005 PSCR Reconciliation which is in an under-collected position. The order resulted in a reduction of pre-tax income of approximately $58 million.

The following graph depicts the total electric Customer Choice volumes for customers who have purchased power from an alternative electric supplier:

Electric Customer Choice Volumes in MWh



In March 2006, the MPSC issued an order directing Detroit Edison to show cause by June 1, 2006 why its retail electric rates should not be reduced in 2007. The MPSC issued an order approving the settlement agreement in this proceeding on August 31, 2006. The order provided for an annualized rate reduction of $53 million for 2006, effective September 5, 2006. Beginning January 1, 2007, and continuing until the later of March 31, 2008 or 12 months from the filing date of Detroit Edison's next main rate case, rates will be reduced by an additional $26 million, for a total reduction of $79 million. Detroit Edison experienced a rate reduction of approximately $13 million in 2006 as a result of this order. The revenue reduction is net of the recovery of the amortization of the costs associated with the implementation of the Performance Excellence Process. The settlement agreement provides for some level of realignment of the existing rate structure by allocating a larger percentage share of the rate reduction to the commercial and industrial customer classes than to the residential customer classes.

Coal Supply — Our generating fleet produces approximately 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.

Nuclear Fuel - 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. We have a contract with the U.S. Department of Energy (DOE) for the future storage and disposal of spent nuclear fuel from Fermi 2. We are 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, we are responsible for the spent nuclear fuel storage. We are currently expanding the Fermi 2 spent fuel pool capacity to meet our storage requirements through 2009. We are 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.

NON-UTILITY OPERATIONS

We have made significant investments in non-utility asset-intensive businesses. We employ disciplined investment criteria when assessing opportunities that leverage our 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. A number of factors have impacted our non-utility businesses including the effect of oil prices on the synthetic fuel business, losses from certain power generation assets, losses from our waste coal recovery and landfill gas recovery businesses, and earnings volatility in our energy trading business. As part of a strategic review of our non-utility operations, we are considering various actions including the sale, restructuring or recapitalization of various non-utility businesses which we expect may generate over $800 million in cash proceeds in 2007. We plan to continue to invest in focused areas that have the strongest opportunities.

The primary source of recent investment capital has been cash flow from the synfuel business. We have hedged a portion the risk of an oil price-related phase-out of production tax credits in the synfuel business. We now anticipate approximately $900 million of synfuel-related cash impacts from 2007 through 2009, which consists of cash from operations and proceeds from option hedges, and approximately $500 million of tax credit carryforward utilization and other tax benefits that are expected to reduce future tax payments. Tax credit carryforward utilization in part could be extended past 2009, if taxable income is reduced from current forecasts.

Coal and Gas Midstream

We are continuing to build our capacity to transport greater amounts of western coal and to expand into coal terminals to allow for increased coal storage and blending. We are currently involved in a contract dispute with BNSF Railway Company that has been referred to arbitration. Under this contract, BNSF transports western coal east for Detroit Edison and the Coal Transportation and Marketing business. We have filed a breach of contract claim against BNSF for the failure to provide certain services that we believe are required by the contract. The arbitration hearing is scheduled for mid-2007. While we believe we will prevail on the merits in this matter, a negative decision with respect to the significant issues being heard in the arbitration could have an adverse effect on our ability to grow the Coal Transportation and Marketing business as currently contemplated.

Pipelines, Processing and Storage is continuing its steady growth plan of expansion of storage capacity in Michigan and expanding and building new pipeline capacity to serve markets in the Midwest and northeast United States.

Unconventional Gas Production

Current natural gas prices provide attractive opportunities for our Unconventional Gas Production business segment. We are an experienced operator with more than 15 years of experience in the Antrim shale in northern Michigan, and we continue to expand our operations in the Barnett shale basin in north Texas, where recent leasehold acquisitions have increased our total leasehold acreage to 89,808 acres (80,530 net of interest of others) after reduction by opportunistic sales of 11,193 acres.

We are exploring the sale of a portion of our Unconventional Gas Production assets which will allow us to monetize value from our more mature holdings, while retaining the ability to benefit from the upside of our earlier stage holdings.

Antrim shale — We intend to develop existing acreage using the latest vertical and horizontal drilling and fracture stimulation techniques. Our long-term fixed-price obligations for production of Antrim continue to expire in 2007. This will create opportunities to remarket Antrim production at significantly higher current market rates.

Michigan – Antrim Shale

	2006	2005	2004
Net Producing Wells	**1,700**	1,630	1,523
Production Volume (Bcfe)	**22**	22	23
Proved Reserves (Bcfe)	**442**	338	335
Net Developed Acreage	**228,232**	217,643	213,959
Net Undeveloped Acreage	**66,184**	73,056	79,025
Capital Expenditures (in Millions)	**$ 49**	$ 37	$ 22
Future Undiscounted Net Cash Flows (in Millions)(1)	**$ 1,636**	$ 1,307	$ 760
Average gas price with hedges (per Mcf)	**$ 3.41**	$ 3.10	$ 3.10
Average gas price without hedges (per Mcf)(2)	**$ 6.61**	$ 7.73	$ 5.57

(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 began to expire in 2006. 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.

Texas – Barnett Shale

	2006	2005	2004
Net Producing Wells	**110**	55	1
Production Volume (Bcfe)	**4**	1	—
Proved Reserves (Bcfe)	**174**	59	8
Net Developed Acreage	**16,045**	14,637	316
Net Undeveloped Acreage	**64,485**	61,627	48,541
Capital Expenditures (in Millions)	**$ 137**	$ 107	$ 16
Future Undiscounted Net Cash Flows (in Millions) (1)	**$ 472**	$ 127	$ 7
Average gas price (per Mcf)	**$ 5.66**	$ 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.

Current natural gas prices and successes within the Barnett shale are resulting in more capital 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 invested $186 million in

2006 and expect to invest a combined amount of approximately $150 million to $170 million in our unconventional gas business in 2007.

As a component of our risk management strategy for our Barnett shale reserves, we hedged a portion of our proved developed producing reserves to secure an attractive investment return. As of December 31, 2006, we entered into a series of cash flow hedges for 4.7 Bcf of anticipated gas production through 2010 at an average price of $8.08 per Mcf.

Power and Industrial Projects

Power and Industrial Projects is comprised primarily of projects that deliver utility-type services to industrial, commercial and institutional customers, and biomass energy projects. We provide utility-type services using project assets usually located on the customers' premises in the steel, automotive, pulp and paper, airport and other industries. These services include pulverized coal and petroleum coke supply, power generation, steam production, chilled water production, wastewater treatment and compressed air supply. We own and operate three gas-fired peaking electric generating plants and a biomass-fired electric generating plant and operate one additional gas-fired power plant under contract. Additionally, we own a gas-fired peaking electric generating plant that was taken out of service in September 2006. We develop, own and operate landfill gas recovery systems throughout the United States. We produce coke from two coke batteries. The production of coke from our coke batteries generates production tax credits (assuming no phase-out).

We are exploring the combination of a sale of an equity interest in, and recapitalization of, some of the assets of the Power and Industrial Projects business, including the sale or restructuring of the power generation assets. In February 2007, we entered into an agreement to sell our Georgetown peaking electric generating facility. The sale is subject to receipt of regulatory approval and is expected to close in the second half of 2007.

Energy Trading

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 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 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 may incur mark-to-market accounting gains or losses in one period that will reverse in subsequent periods when transactions are settled.

During 2005, our earnings were negatively impacted by the economically favorable decision 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. In addition, we entered into forward power contracts to economically hedge certain physical and capacity power contracts. The financial impacts of these timing differences have begun to reverse and have favorably impacted results during 2006. We are exploring strategic options for the energy trading business.

Synthetic Fuel

Synthetic Fuel Operations

Synfuel plants chemically change coal and waste 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 and are available through December 31, 2007. The synthetic fuel plants generate operating losses which we expect to be offset by production tax credits. The value of a production tax credit is adjusted annually by an inflation factor and published annually by the Internal Revenue Service (IRS). The value is reduced if the Reference Price of a barrel of oil exceeds certain thresholds.

We are the operator of nine synthetic fuel production facilities throughout the United States. On May 12, 2006, we idled production at all nine of the synthetic fuel facilities. The decision to idle synfuel production was driven by the level and volatility of oil prices at that time. During the idle period, we took various steps to reduce our oil price exposure, including renegotiation of a significant number of commercial agreements. Beginning September 5, 2006 through October 4, 2006, we resumed production at each of the nine synfuel facilities due to these amended commercial agreements and declines in the level of oil prices.

Recognition of Synfuel Gains

To optimize income and cash flow from the synfuel operations, we sold interests in all nine of the facilities, representing 91% of the total production capacity as of December 31, 2006. Proceeds from the sales are contingent upon production levels and the value of credits generated. Gains from the sale of an interest in a synfuel project are recognized when there is persuasive evidence that the sales proceeds have become fixed or determinable, the probability of refund is considered remote and collectibility is assured. In substance, we receive synfuel gains and reduced operating losses in exchange for tax credits associated with the projects sold.

The gain from the sale of synfuel facilities is generally comprised of fixed and variable components. The fixed component represents note payments, 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 and is subject to refund based on the annual oil price phase-out. The variable component is recognized as a gain only when the probability of refund is considered remote and collectibility is assured. Additionally, our partners reimburse us (through the project entity) for the operating losses of the synfuel facilities, referred to as capital contributions. In the event that the tax credit is phased out, we are contractually obligated to refund an amount equal to all or a portion of the operating losses funded by our partners. To assess the probability and estimate the amount of refund, we use valuation and analysis models that calculate the probability of the Reference Price of oil for the year being within or exceeding the phase-out range. Due to changes in the agreements with certain of our synfuel partners and the exercise of existing rights by other synfuels partners, a higher percentage of the payments in 2006 were variable payments. As a result, a larger portion of the 2006 synfuel payments are subject to refund as a result of the phase-out; and therefore reduced the gain associated with the payments.

Crude Oil Prices

The Reference Price of a barrel of oil is an estimate by the IRS of the annual average wellhead price per barrel for domestic crude oil. The value of the production tax credit in a given year is reduced if the Reference Price of oil over the year exceeds a threshold price and is eliminated entirely if that same Reference Price exceeds a phase-out price. During 2006, the annual average wellhead price is projected to be 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 2005 through 2007 are as follows:

	Reference Price	Beginning Phase-Out Price	Ending Phase-Out Price
2005 (actual)	$ 50.26	$ 53.20	$ 66.79
2006 (estimated)	$ 60	$ 55	$ 69
2007 (estimated)	Not Available	$ 56	$ 70

The NYMEX daily closing price of a barrel of oil for 2006 averaged approximately $66, which is approximately equal to a Reference Price of $60 per barrel, which we estimate to be within the phase-out range. The actual tax credit phase-out for 2006 will not be certain until the Reference Price is published by the IRS in April 2007. There is a risk of at least a partial phase-out of the production tax credits in 2007, which could adversely impact our results of operations, cash flow, and financial condition.

Hedging of Synfuel Cash Flows

As discussed in Note 2 of the Notes to Consolidated Financial Statements, we have entered into derivative and other contracts to economically hedge a portion of our synfuel cash flow exposure 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. To manage our exposure in 2007 to the risk of an increase in oil prices that could substantially 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' 2007 average 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 2007 are less than approximately $60 per barrel, the derivatives will yield no payment. If the average NYMEX prices of oil exceed approximately $60 per barrel, 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 $76 per barrel. These contracts are based on various terms to take advantage of increases in oil prices. We recorded pretax mark-to-market gains of $60 million during 2006 and $47 million in 2005, and a $12 million loss in 2004. The fair value changes are recorded as adjustments to the gain from selling interests in synfuel facilities and are included in the Asset gains and losses, reserves and impairments, net line item in the Consolidated Statement of Operations. We paid approximately $50 million for 2006 hedges, for which we received payments of approximately $156 million upon settlement of these hedges in January 2007. Through December 31, 2006, we paid approximately $103 million for 2007 hedges which will provide protection for a significant portion of our cash flows related to the synfuel production during 2007. As part of our synfuel- related risk management strategy, we continue to evaluate alternatives available to mitigate unhedged exposure to oil price volatility. As our risk management position changes due to market volatility, we may adjust our hedging strategy in response to changing conditions.

Risks and Exposures

Since there was the likelihood that the Reference Price for a barrel of oil would remain above the threshold at which synfuel-related production tax credits began to phase-out, we deferred gain recognition associated with variable and certain fixed note payments in 2006 until the end of the year when the probability of refund was remote and collectibility was assured. We deferred all variable gains for the first three quarters of 2006 and 2005. We recognized $43 million of fixed gains and $14 million of variable gains in 2006, compared to fixed gains of $132 million and variable gains of $187 million in 2005. All or a portion of the deferred gains will be recognized when and if the gain recognition criteria is met. Additionally, we may establish reserves for potential refunds of amounts related to partners' capital contributions associated with operating losses allocated to their account. As previously discussed, in the event of a tax credit phase-out, we are contractually obligated to refund to our partners all or a portion of the operating losses funded by our partners.

In 2006, we recorded reserves and impairments of $157 million, consisting of a $79 million reserve for capital contributions related to operating losses and an impairment of $78 million for synfuel-related fixed assets and inventory. The fixed asset impairment was partially offset by $70 million included in the Minority Interest line on our Consolidated Statement of Operations, representing our partners' share of the asset write down.

Cash from synfuel activity is at risk of a phase-out of the production tax credits. We expect approximately $900 million of synfuel-related cash impacts from 2007 through 2009, which consists of cash from operations, asset sales, and proceeds from option hedges, and approximately $500 million of tax credit carryforward utilization and other tax benefits that are expected to reduce future tax payments. The expected cash flow of approximately $900 million is economically hedged against the movement in oil prices. In addition, a goodwill write-off of up to $4 million will likely be required in 2007 due to the production tax credit phase-out, the inability to generate new production tax credits after 2007 and the resulting discontinuance of synfuel production. We have fixed note receivables associated with the sales of interests in the synfuel facilities. A partial or full phase-out of production tax credits could adversely affect the collectibility of our receivables. The cash flow impact would likely reduce our ability to execute our investment and growth strategy.

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 is 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. Detroit Edison’s CTA is estimated to total between $160 million and $190 million. MichCon’s CTA is estimated to total between $55 million and $60 million.We estimate savings of approximately $45 million in operation and maintenance expenses and capital costs were realized in 2006. In 2006, we recorded CTA of approximately $134 million. CTA in 2006 exceeded our savings, but we expect to realize sustained net cost savings beginning in 2007.

In September 2006, the MPSC issued an order approving a settlement agreement that allows Detroit Edison and MichCon, commencing in 2006, to defer the incremental CTA. Further, the order provides for Detroit Edison and MichCon to amortize the CTA deferrals over a ten-year period beginning with the year subsequent to the year the CTA was deferred. Detroit Edison deferred approximately $102 million of CTA in 2006 as a regulatory asset and will begin amortizing deferred 2006 costs in 2007 as the recovery of these costs was provided for by the MPSC in the order approving the settlement in the show cause proceeding. MichCon cannot defer CTA costs at this time because a recovery mechanism has not been established.

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 $4.3 billion, including increased environmental requirements and reliability enhancement projects through 2011. Our gas utility currently expects to invest approximately $1.0 billion 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 consistent with prior treatment.

In 2005, we launched the first phase of our Enterprise Business Systems project, an enterprise resource planning system initiative to improve existing processes and to implement new core information systems. Through December 2006, we have spent approximately $330 million on this project and we anticipate spending an additional $45 million to $70 million over the next year as the remaining system elements are developed and implemented.

In the future, we may build a new base-load coal or nuclear electric generating plant. The last base-load plant constructed within our electric utility service territory was approximately twenty years ago.

OUTLOOK

The next few years will be a period 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 at the federal level. However, the expected industry consolidation, resulting in the creation of large regional utility providers, has been recently impacted by actions of regulators in certain states affected by the proposed transactions.

Looking forward, we will focus on several areas 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; and
- investing in businesses that integrate our assets and leverage our skills and expertise.

Along with pursuing a leaner organization, we anticipate approximately $900 million of synfuel-related cash impacts from 2007 through 2009, which consists of cash from operations and proceeds from option hedges, and approximately $500 million of tax credit carryforward utilization and other tax benefits that are expected to reduce future tax payments. The redeployment of this cash represents a unique opportunity to increase shareholder value and strengthen our balance sheet. We expect to use any such cash and the potential cash from monetization of certain of our non-utility assets and operations to reduce debt and repurchase common stock, and to continue to pursue growth investments that meet our strict risk-return and value creation criteria. Our objectives for cash redeployment are to strengthen the balance sheet and coverage ratios to improve our current credit rating and outlook, and to have any monetizations be accretive to earnings per share.

RESULTS OF OPERATIONS

Net income in 2006 was $433 million, or $2.43 per diluted share, compared to net income of $537 million, or $3.05 per diluted share in 2005 and net income of $431 million, or $2.49 per diluted share in 2004. Excluding discontinued operations and the cumulative effect of accounting changes, our income from continuing operations in 2006 was $437 million, or $2.45 per diluted share, compared to income of $577 million, or $3.28 per diluted share in 2005 and income of $464 million, or $2.68 per diluted share in 2004. The following sections provide a detailed discussion of our segments' operating performance and future outlook.

Segments realigned — In the third quarter of 2006, we realigned the non-utility segment Power and Industrial Projects business unit to separately present the Synthetic Fuel business. The impending expiration of synfuel tax credits as of December 31, 2007, combined with the sustained volatility of oil prices, increased management focus on synfuels, thereby requiring a separate business segment. In the fourth quarter of 2006, we separated the Fuel Transportation and Marketing segment into Coal and Gas Midstream, and Energy Trading corresponding to additional management focus on the results of these non-utility segments. Based on the following structure, we set strategic goals, allocate resources and evaluate performance:

- *Electric Utility*, consisting of Detroit Edison;
- *Gas Utility*, primarily consisting of MichCon;
- Non-utility Operations
  - *Coal and Gas Midstream*, primarily consisting of coal transportation and marketing, gas pipelines and storage;
  - *Unconventional Gas Production,* primarily consisting of unconventional gas project development and production;
  - *Power and Industrial Projects*, primarily consisting of on-site energy services, steel-related projects and power generation with services;
  - *Energy Trading,* consisting of energy marketing and trading operations; and
  - *Synthetic Fuel,* consisting of the operations of the nine synfuel plants.

- *Corporate & Other*, primarily consisting of corporate staff functions and certain energy technology investments.

(in Millions, except per share data)	2006	2005	2004
Net Income by Segment:			
Electric Utility	**$ 325**	$ 277	$ 150
Gas Utility	**50**	37	20
Non-utility Operations:			
Coal and Gas Midstream	**50**	45	33
Unconventional Gas Production	**9**	4	6
Power and Industrial Projects	**(80)**	4	(17)
Energy Trading	**96**	(43)	85
Synthetic Fuel	**48**	305	199
Corporate & Other	**(61)**	(52)	(12)
Income (Loss) from Continuing Operations:			
Utility	**375**	314	170
Non-utility	**123**	315	306
Corporate & Other	**(61)**	(52)	(12)
	437	577	464
Discontinued Operations	**(5)**	(37)	(33)
Cumulative Effect of Accounting Changes	**1**	(3)	—
Net Income	**$ 433**	$ 537	$ 431
Diluted Earnings (Loss) Per Share			
Total Utility	**$ 2.10**	$ 1.78	$ .98
Non-utility Operations	**.69**	1.79	1.77
Corporate & Other	**(.34)**	(.29)	(.07)
Income from Continuing Operations	**2.45**	3.28	2.68
Discontinued Operations	**(.03)**	(.21)	(.19)
Cumulative Effect of Accounting Changes	**.01**	(.02)	—
Net Income	**$ 2.43**	$ 3.05	$ 2.49

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 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 electric energy to approximately 2.2 million customers in southeastern Michigan.

Factors impacting income: Our net income increased $48 million and $127 million in 2006 and 2005, respectively. These results primarily reflect higher gross margins, partially offset by increased depreciation and amortization expenses. Additionally, 2005 results were affected by 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, 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)	2006	2005	2004
Operating Revenues	**$ 4,737**	$ 4,462	$ 3,568
Fuel and Purchased Power	**1,566**	1,590	885
Gross Margin	**3,171**	2,872	2,683
Operation and Maintenance	**1,336**	1,308	1,395
Depreciation and Amortization	**809**	640	523
Taxes Other Than Income	**252**	241	249
Asset (Gains) and Losses, Net	**(6)**	(26)	(1)
Operating Income	**780**	709	517
Other (Income) and Deductions	**294**	283	303
Income Tax Provision	**161**	149	64
Net Income	**$ 325**	$ 277	$ 150
Operating Income as a Percent of Operating Revenues	**16%**	16%	14%

Gross margin increased $299 million during 2006 and $189 million in 2005. The 2006 improvement was primarily due to increased rates due to the expiration of the residential rate cap on January 1, 2006 and returning sales from electric Customer Choice, partially offset by milder weather. The increase in 2005 was due to higher demand resulting from warmer weather 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. Gross margin was favorably impacted by decreased electric Customer Choice penetration, whereby we lost 6% of retail sales to electric Customer Choice customers in 2006 and 12% of such sales during 2005 as retail customers migrated back to us as their electric generation provider rather than remaining with alternative suppliers. 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 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)	2006	2005
Weather-related margin impacts	**$ (81)**	$ 166
Removal of residential rate caps effective January 1, 2006	**186**	—
Return of customers from electric Customer Choice	**156**	79
Service territory economic performance	**(16)**	(23)
Impact of MPSC 2004 rate orders	**26**	116
Unrecovered power supply costs — residential customers	**—**	(73)
Transmission charges	**—**	(93)
Other, net	**28**	17
Increase in gross margin performance	**$ 299**	$ 189

Power Generated and Purchased

(in Thousands of MWh)	2006		2005		2004	
Power Plant Generation						
Fossil	**39,686**	**70%**	40,756	73%	39,432	75%
Nuclear	**7,477**	**13**	8,754	16	8,440	16
	47,163	**83**	49,510	89	47,872	91
Purchased Power	**9,861**	**17**	6,378	11	4,650	9
System Output	**57,024**	**100%**	55,888	100%	52,522	100%
Less Line Loss and Internal Use	**(3,603)**		(3,205)		(3,574)	
Net System Output	**53,421**		52,683		48,948	
Average Unit Cost ($/MWh)						
Generation (1)	**$ 15.61**		$ 15.47		$ 12.98	
Purchased Power (2)	**$ 53.71**		$ 89.37		$ 37.06	
Overall Average Unit Cost	**$ 22.20**		$ 23.90		$ 15.11	

(1) Represents fuel costs associated with power plants.

(2) The change in purchased power costs were driven primarily by seasonal demand and coal and gas prices.

(in Thousands of MWh)	2006	2005	2004
Electric Sales			
Residential	**15,769**	16,812	15,081
Commercial	**17,948**	15,618	13,425
Industrial	**13,235**	12,317	11,472
Wholesale	**2,826**	2,329	2,197
Other	**402**	390	401
	50,180	47,466	42,576
Interconnection sales (1)	**3,241**	5,217	6,372
Total Electric Sales	**53,421**	52,683	48,948
Electric Deliveries			
Retail and Wholesale	**50,180**	47,466	42,576
Electric Customer Choice	**2,694**	6,760	9,245
Electric Customer Choice—Self Generators (2)	**909**	518	595
Total Electric Sales and Deliveries	**53,783**	54,744	52,416

(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 increased $28 million in 2006 and decreased $87 million in 2005. The 2006 increase was primarily due to increased distribution system maintenance of $35 million and increased plant outages of $33 million which was partially offset by $36 million of lower storm expenses. Pursuant to MPSC authorization, Detroit Edison deferred approximately $102 million of CTA in 2006. The comparability of 2005 to 2004 is affected by the November 2004 MPSC final rate order which required transmission and MISO expenses to be included in purchased power expense with related revenues to be recorded through the PSCR mechanism. Additionally, the DTE Energy parent company no longer allocated merger-related interest as a result of the November 2004 MPSC final rate order, which was partially offset by higher 2005 storm expenses.

Depreciation and amortization expense increased $169 million and $117 million in 2006 and 2005, respectively. The 2006 increase was due to a $112 million net stranded cost write-off related to the September 2006 MPSC order regarding stranded costs and a $19 million increase in our asset retirement obligation at our Fermi 1 nuclear facility. We also had increased amortization of regulatory assets of $19 million related to electric Customer Choice and $8 million related to our securitized assets. The 2005 increase reflects the income effect of recording regulatory assets in 2004, which lowered depreciation and amortization expenses. The regulatory asset deferrals totaled $46 million in 2005 and $107 million in 2004. Additionally, higher 2005 sales volumes compared to 2004 resulted in greater amortization of regulatory assets.

Asset (gains) and losses, net decreased $20 million in 2006 and increased $25 million in 2005 primarily as a result of our 2005 sale of land near our headquarters in Detroit, Michigan.

Other income and deductions expense increased $11 million in 2006 and decreased $20 million in 2005. The 2006 increase is attributable to higher interest expense due to increased long-term debt. 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.

Outlook — We continue to improve the operating performance of Detroit Edison. During the past year, we have resolved a portion of our regulatory issues and continue to pursue additional regulatory and/or legislative solutions for structural problems within the Michigan market structure, primarily 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 continue to improve performance. Looking forward, additional issues, such as rising prices for coal, health care and higher levels of 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 Energy Operating System and the Performance Excellence Process to seek opportunities to improve productivity, remove waste and 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 coal or nuclear facility. While we have not decided on construction of a new base-load nuclear facility, in February 2007, we announced that we will prepare a license application for construction and operation of a new nuclear power plant on the site of Fermi 2. By completing the license application before the end of 2008, we may qualify for financial incentives under the federal Energy Policy Act of 2005. We are also studying the possible transfer of a gas-fired peaking electric generating plant from our non-utility operations to our electric utility to support future power generation requirements.

The following variables, either in combination or acting alone, could 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 and maximize plant performance;
- variations in market prices of power, coal and gas;
- 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 6 of the Notes to Consolidated Financial Statements.

In January 2007, the MPSC submitted the State of Michigan's 21st Century Energy Plan to the Governor of Michigan. The plan recommends that Michigan's future energy needs be met through a combination of renewable resources and cleanest generating technology, with significant energy savings achieved by increased energy efficiency. The plan also recommends:

- a requirement that all retail electric suppliers obtain at least 10 percent of their energy supplies from renewable resources by 2015;
- an opportunity for utility-built generation, contingent upon the granting of a certificate of need and competitive bidding of engineering, procurement and construction services;
- investigating the cost of a requirement to bury certain power lines; and
- creation of a Michigan Energy Efficiency Program, administered by a third party under the direction of the MPSC with initial funding estimated at $68 million.

We continue to review the energy plan and are unable to predict the impact on the Company of the implementation of the plan.

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 to approximately 17,000 customers.

Factors impacting income: Gas Utility's net income increased $13 million in 2006 and increased $17 million in 2005. The variances were primarily attributable to increased rates and the impacts in 2005 of the MPSC's April 2005 gas cost recovery and gas rate orders and the effect of milder weather in 2006.

The 2005 MPSC 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)	**2006**	2005	2004
Operating Revenues	**$ 1,849**	$ 2,138	$ 1,682
Cost of Gas	**1,157**	1,490	1,071
Gross Margin	**692**	648	611
Operation and Maintenance	**431**	424	403
Depreciation and Amortization	**94**	95	103
Taxes Other Than Income	**53**	43	49
Asset (Gains) and Losses, Net	**—**	4	(3)
Operating Income	**114**	82	59
Other (Income) and Deductions	**53**	47	48
Income Tax Provision (Benefit)	**11**	(2)	(9)
Net Income	**$ 50**	$ 37	$ 20
Operating Income as a Percent of Operating Revenues	**6%**	4%	4%

Gross margin increased $44 million and $37 million in 2006 and 2005, respectively. Gross margins were favorably affected by higher base rate revenues of $15 million and $42 million in 2006 and 2005, respectively. Revenue associated with the uncollectible expense tracking mechanism authorized by the MPSC in the April 2005 gas rate order, increased $22 million and $11 million in 2006 and 2005, respectively. Additionally, 2006 was impacted by a $17 million favorable impact in lost gas recognized and an increase of $24 million in midstream services including storage and transportation. Partially offsetting these increases were declines of $31 million due to warmer than normal weather and $26 million as a result of customer conservation and lower volumes. The comparability of 2006 to 2005 is also affected

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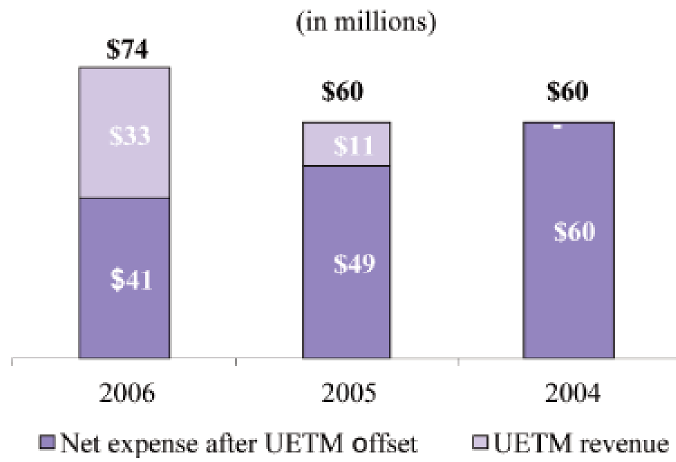
by an adjustment we recorded in the first quarter of 2005 related to an April 2005 MPSC order in our 2002 GCR reconciliation case that disallowed $26 million representing unbilled revenues at December 2001.

	2006	2005	2004
Gas Markets (in Millions)			
Gas sales	**$ 1,541**	$ 1,860	$ 1,435
End user transportation	**135**	134	119
	1,676	1,994	1,554
Intermediate transportation	**69**	58	56
Other	**104**	86	72
	$ 1,849	$ 2,138	$ 1,682
Gas Markets (in Bcf)			
Gas sales	**138**	168	173
End user transportation	**136**	157	145
	274	325	318
Intermediate transportation	**373**	432	536
	647	757	854

The 2005 final rate order provided revenue for an uncollectible expense true-up mechanism (UETM) to mitigate the effect of increasing uncollectible expense. The revenue recorded related to the UETM was $33 million for 2006 and $11 million for 2005.

Uncollectible Accounts Expense



Operation and maintenance expense increased $7 million and $21 million in 2006 and 2005, respectively. The 2006 increase is due to a $14 million increase in uncollectible accounts receivable expense, 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. In 2006, we recorded $24 million in implementation costs associated with our Performance Excellence Process and we recognized $9 million of lower injuries and damages expenses and lower labor and employee incentives. The comparability of 2006 to 2005 and the comparability of 2005 to 2004 was affected by an adjustment we recorded in the second quarter of 2005 for the disallowance of $11 million in environmental costs due to the April 2005 final gas rate order and the requirement to defer negative pension expense as a regulatory liability. Additionally, the comparability was impacted by the DTE Energy parent company no longer allocating $9 million of merger-related interest to MichCon effective in April 2005.

Asset (gains) and losses, net increased $4 million and decreased $7 million in 2006 and 2005, respectively. The 2006 change was due to a $3 million gain on the sale of investment rights related to storage field construction which was offset by a $3 million loss due to a reduction to MichCon's 2004 GCR underrecovery related to the accounting treatment of the injected base gas remaining in the New Haven storage field when it was sold in early 2004. The $7 million decline in 2005 was primarily the result of a write-off of certain computer equipment and related depreciation resulting from the April 2005 final rate order.

Income tax provision increased by $13 million in 2006 and income tax benefit decreased $7 million in 2005 primarily due to variations in pre-tax earnings.

Outlook — Operating results are expected to vary due to regulatory proceedings, weather, changes in economic conditions, customer conservation and process improvements. Higher gas prices and economic conditions have resulted in continued pressure on receivables and working capital requirements that are partially mitigated by the GCR mechanism. 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.

We will utilize the DTE Energy Operating System and the Performance Excellence Process to seek opportunities to improve productivity, remove waste and decrease our costs while improving customer satisfaction.

NON-UTILITY OPERATIONS

Coal and Gas Midstream

Coal and Gas Midstream consists of Coal Transportation and Marketing and the Pipelines, Processing and Storage businesses.

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 marketing and coal-to-power tolling transactions, as well as the purchase and sale of emissions credits. We perform 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 owns a partnership interest in an interstate transmission pipeline, six carbon dioxide processing facilities and two natural gas storage fields. The pipeline and storage assets are primarily supported by stable, long-term fixed price revenue contracts. The assets of these businesses are well integrated with other DTE Energy operations. Pursuant to an operating agreement, MichCon provides physical operations, maintenance and technical support for the Washington 28 and Washington 10 storage facilities.

Factors impacting income: Net income increased $5 million and $12 million in 2006 and 2005, respectively.

(in Millions)	2006	2005	2004
Operating Revenues	**$ 707**	$ 707	$ 589
Operation and Maintenance	**628**	653	542
Depreciation and Amortization	**4**	3	3
Taxes Other Than Income	**5**	4	4
Operating Income	**70**	47	40
Other (Income) and Deductions	**(8)**	(20)	(12)
Income Tax Provision	**28**	22	19
Net Income	**$ 50**	$ 45	$ 33

Operating revenues remained the same in 2006 and increased $118 million in 2005. In 2006 our Coal Transportation and Marketing business experienced lower synfuel related volumes which were offset by an increase in storage revenues in the Pipelines, Processing and Storage business. During 2005, our Coal Transportation and Marketing business experienced higher throughput volumes and increased prices for coal.

Operation and maintenance expense decreased $25 million in 2006 and increased $111 million in 2005**.** The 2006 decrease was due to lower synfuel related volumes and decreased expenses at our Coal Transportation and Marketing business due to decreased marketing volume. During 2005, our Coal Transportation and Marketing business experienced higher throughput volumes and increased prices for coal.

Other (income) and deductions decreased $12 million in 2006 and increased $8 million in 2005. The 2006 decrease is primarily attributed to higher interest expense as a result of our storage expansion construction.

Income tax provision increased $6 million for 2006 and increased $3 million in 2005 reflecting variations in pre-tax income.

Outlook — We expect to continue to grow our Coal Transportation and Marketing business in a manner consistent with, and complementary to, the growth of our other business segments. However, a portion of our Coal Transportation and Marketing revenues and net income are dependent upon our Synfuel operations and were adversely impacted by the temporary idling of the synfuel facilities in 2006. Coal Transportation and Marketing is involved in a contract dispute with BNSF Railway Company that has been referred to arbitration. See Note 15 of the Notes to Consolidated Financial Statements.

Our Pipeline, Processing and Storage business will continue its steady growth plan. In April 2006, Pipelines, Processing and Storage placed into service over 14 Bcf of storage capacity at an existing Michigan storage field and plans to file a MPSC application early in 2007 for a new gas storage reservoir which will increase its overall working gas storage capacity by 8.0 Bcf to a total of 74 Bcf. In December 2006, Washington 28 filed an application with the MPSC requesting an increase in its working gas storage capacity to 16.0 Bcf. 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 received FERC approval for this expansion in October 2006. Pipeline, Processing and Storage has a 26.25% ownership interest in Millennium Pipeline which received FERC approval for construction and operation in December 2006. Millennium Pipeline is scheduled to be in service in late 2008. In October 2006, we purchased the lessor interest in the 66 Bcf Washington 10 gas storage field. Prior to the purchase, we leased the storage rights and lease obligations were recorded as operating leases. We plan to expand existing assets and develop new assets which are typically supported with long-term customer commitments.

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 Energy Trading segment.

Factors impacting income: Net income increased $5 million in 2006 and decreased $2 million in 2005. The 2006 results were primarily impacted by an increase in Barnett shale production and an increase in net gas prices for Antrim shale. Partially offsetting these revenue increases were higher operating and depletion expenses associated with increased production and the operation of new wells. The decline in 2005 was due to higher operating and Michigan severance tax expenses.

(in Millions)	2006	2005	2004
Operating Revenues	**$ 99**	$ 74	$ 71
Operation and Maintenance	**37**	30	27
Depreciation, Depletion and Amortization	**27**	20	18
Taxes Other Than Income	**11**	11	7
Asset (Gains) and Losses, Net	**(3)**	—	—
Operating Income	**27**	13	19
Other (Income) and Deductions	**13**	8	10
Income Tax Provision	**5**	1	3
Net Income	**$ 9**	$ 4	$ 6

Operating revenues increased $25 million in 2006 due to increased Barnett shale production and increased $3 million in 2005 due primarily to higher gas prices.

Operation and maintenance expense increased $7 million in 2006 and $3 million in 2005. Increases are associated with the addition of approximately 285 net producing wells during the three-year period.

Depreciation, depletion and amortization increased $7 million in 2006 and $2 million in 2005. The year-to-year increases were associated with higher gas production and higher finding costs associated with Barnett shale wells.

Taxes other than income were the same in 2006 due to severance taxes that were impacted by lower gas prices, which was offset by higher gas production, and increased $4 million in 2005 due to higher severance taxes associated with gas price increases on relatively flat Antrim gas volumes.

Assets (gains) and losses, net increased $3 million in 2006 primarily due to the sale of a working interest in unproved property.

Other (income) and deductions increased $5 million in 2006 and decreased $2 million in 2005. Interest expense was the primary contributor to the variances. The 2006 increase in interest expense was attributed to higher average affiliate notes payable balances.

Outlook — We expect to continue to develop our proved areas and test unproved areas in Michigan and Texas. Evaluation of Barnett shale test wells in up to three new areas is ongoing. During 2007, we expect Barnett Shale production of 8.7 Bcfe of natural gas compared with approximately 4.1 Bcfe in 2006 and Antrim Shale production roughly equivalent to the 21.5 Bcfe produced in 2006. We expect to invest a combined amount of approximately $150 million to $170 million in our Unconventional Gas Production business in 2007. We are exploring the sale of a portion of our Unconventional Gas Production assets which will allow us to monetize value from our more mature holdings, while retaining the ability to benefit from the upside of our earlier stage holdings.

Power and Industrial Projects

Power and Industrial Projects is comprised primarily of projects that deliver utility-type services to industrial, commercial and institutional customers, and biomass energy projects. We provide utility-type services using project assets usually located on the customers' premises in the steel, automotive, pulp and paper, airport and other industries. These services include pulverized coal and petroleum coke supply, power generation, steam production, chilled water production, wastewater treatment and compressed air supply. We own and operate three gas-fired peaking electric generating plants and a biomass-fired electric generating plant and operate one additional gas-fired power plant under contract. Additionally, we own a gas-fired peaking electric generating plant that was taken out of service in September 2006. We develop, own and operate landfill gas recovery systems throughout the United States. We produce metallurgical coke from two coke batteries. The production of coke from our coke batteries generates production tax credits.

Factors impacting income: Power and Industrial Projects' reported a net loss of $80 million in 2006 and net income of $4 million in 2005. The 2006 net loss is primarily due to impairments. The 2005 net income is attributed to the acquisitions of four on-site energy projects and coke operations in 2005.

(in Millions)	**2006**	2005	2004
Operating Revenues	**$ 409**	$ 428	$ 448
Operation and Maintenance	**366**	329	384
Depreciation and Amortization	**48**	48	53
Taxes other than Income	**12**	14	8
Asset (Gains) and Losses, Reserves and Impairments, Net	**75**	(1)	—
Operating Income (Loss)	**(92)**	38	3
Other (Income) and Deductions	**43**	4	28
Minority Interest	**1**	37	11
Income Taxes			
Provision (Benefit)	**(44)**	5	(10)
Production Tax Credits	**(12)**	(12)	(9)
	(56)	(7)	(19)
Net Income (Loss)	**$ (80)**	$ 4	$ (17)

Operating revenues decreased $19 million in 2006 and $20 million in 2005. The 2006 decrease is primarily due to lower coke prices and lower pulverized coal sales. The 2005 decrease reflects the impact from the sale of our interest in a coke battery in 2005 offset by increases at another owned coke battery due to increased output and increased prices. The 2006 and 2005 decreases were partially offset by increased revenue from our on-site energy projects, 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.

Operation and maintenance expense increased $37 million in 2006 and decreased $55 million in 2005, reflecting the 2005 acquisitions of three on-site energy projects and coke operations. The 2005 decrease reflects the impact from the sale of an interest in a coke battery in 2005 resulting in a decrease in expense offset by increases in costs at another owned coke battery reflecting increased output.

Asset (gains) and losses, reserves and impairments, net increased $76 million in 2006. In 2006, we recorded a $42 million impairment for one of our 100% owned natural gas-fired generating plants and a $14 million impairment at our landfill gas recovery unit relating to the write-down of long-lived assets at several landfill sites. Also, during 2006, we recorded a pre-tax impairment loss of $19 million for the write down of fixed assets and patents at our waste coal recovery business.

Other income and deductions increased $39 million in 2006 primarily due to a $32 million impairment of a 50% equity interest in a natural gas-fired generating plant.

Income taxes declined $49 million in 2006 and increased $12 million in 2005, reflecting changes in pre-tax income.

Outlook – 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. The coke battery and landfill gas recovery businesses generate production tax credits that are subject to an oil price-related phase-out. Due to the relatively low level of production tax credits generated by our coke battery and landfill gas recovery business, a partial or full phase-out of production tax credits in these two businesses is not expected to have a material adverse impact on our Consolidated Statements of Operations, Cash Flow and Financial Position. We are exploring the combination of a sale of an equity interest in, and recapitalization of, some of the assets of the Power and Industrial Projects business, including the sale or restructuring of the power generation assets. In February 2007, we entered into an agreement to sell our Georgetown peaking electric generating facility. The sale is subject to receipt of regulatory approval and is expected to close in the second half of 2007.

Energy Trading

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. Energy Trading is integral in providing commodity risk management services to the other unregulated businesses within DTE Energy.

Factors impacting income: Net income increased $139 million in 2006 and decreased $128 million in 2005. The 2006 increase is attributed to increased mark-to-market and realized power and gas positions that resulted from significant 2005 mark-to-market losses on derivative contracts used to economically hedge our gas in storage and forward power contracts. The 2005 decrease is attributed to decreased mark-to-market and realized power and gas positions.

(in Millions)	**2006**	2005	2004
Operating Revenues	**$ 830**	$ 977	$ 665
Fuel, Purchased Power and Gas	**616**	984	486
Gross Margin	**214**	(7)	179
Operation and Maintenance	**65**	43	41
Depreciation and Amortization	**6**	4	3
Taxes Other Than Income	**1**	(1)	—
Operating Income (Loss)	**142**	(53)	135
Other (Income) and Deductions	**(3)**	13	5
Income Tax Provision (Benefit)	**49**	(23)	45
Net Income (Loss)	**$ 96**	$ (43)	$ 85

Gross margin increased $221 million in 2006 and decreased $186 million in 2005. The 2006 increase is attributed to a $168 million mark-to-market increase on power and gas positions and a $57 million increase in realized power and gas positions. The 2006 results reflect the timing differences from 2005 that largely reversed and favorably impacted earnings. The 2005 decrease is due to a $121 million mark-to-market decrease on power and gas positions and a $66 million decrease in realized power and gas positions. The 2005 results reflect 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.

Operation and maintenance expense increased $22 million in 2006 and $2 million in 2005. The 2006 increases were due to higher incentive expenses of $14 million resulting from our strong economic performance and higher corporate allocation charges of $10 million.

Other income and deductions decreased $16 million in 2006 and increased $8 million in 2005. The 2006 decrease is attributed to $6 million of lower intercompany interest expense and $8 million of higher intercompany interest income resulting from favorable operating cash flows to fund intercompany loans.

Income tax provision increased $72 million in 2006 and decreased $68 million in 2005 primarily due to variations in pre-tax earnings.

Outlook - Significant portions of the Energy Trading 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 owned 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 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 manage the price risk of storage with over-the-counter forwards and futures. This results in gains and losses that are recognized in different interim and annual accounting periods. We are exploring strategic options for the energy trading business.

See "Fair Value of Contracts" section that follows.

<u>Synthetic Fuel</u>

Synthetic Fuel is comprised of the nine synfuel plants that we operate and that produce synthetic fuel. The production of synthetic fuel from the synfuel plants generates production tax credits.

Factors impacting income: Synthetic Fuel net income decreased $257 million in 2006 and increased $106 million in 2005. The decline in 2006 was due to higher oil prices resulting in reduced gains from selling interests in our synfuel plants, lower levels of production tax credits and asset impairments and reserves. The increase in 2005 reflects higher gains recognized from selling interests in our synfuel plants, gains on synfuel hedges, and increased levels of production tax credits.

(in Millions)	**2006**	2005	2004
Operating Revenues	**$ 863**	$ 927	$ 650
Operation and Maintenance	**1,019**	1,167	832
Depreciation and Amortization	**24**	58	33
Taxes other than Income	**12**	20	8
Asset (Gains) and Losses, Reserves and Impairments, Net	**40**	(367)	(219)
Operating Income (Loss)	**(232)**	49	(4)
Other (Income) and Deductions	**(20)**	(34)	(43)
Minority Interest	**(251)**	(318)	(223)
Income Taxes			
Provision (Benefit)	**14**	139	92
Production Tax Credits	**(23)**	(43)	(29)
	(9)	96	63
Net Income	**$ 48**	$ 305	$ 199

Operating revenues decreased $64 million in 2006 and increased $277 million in 2005. Revenues were lower in 2006 due to our decision to temporarily idle production at all nine of the synfuel facilities. Revenues increased in 2005 primarily reflecting higher synfuel sales due to increased production.

Operation and maintenance expense decreased $148 million in 2006 and increased $335 million in 2005. Operation and maintenance expense declined in 2006 due to our decision to temporarily idle production at all nine of the synfuel facilities for a portion of the year. Operating and maintenance expense in 2005 increased reflecting costs associated with increased synthetic fuel production.

Asset (gains) and losses, reserves and impairments, net decreased $407 million in 2006 and increased $148 million in 2005. In 2006 and 2005, we deferred gains from the sale of the synfuel facilities, including in 2006, a portion of gains related to fixed payments. Due to the increase in oil prices and the resulting decrease in production and sales volumes, we recorded an accrual for contractual partners' obligations of $79 million pre-tax in 2006 reflecting the possible refund of amounts equal to our partners' capital contributions or for operating losses that would normally be paid by our partners. We recorded other synfuel-related reserves and impairments in 2006 of $78 million. To economically hedge our exposure to the risk of an increase in oil prices and the resulting reduction in 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 net 2006 synfuel hedge mark-to-market gains of $60 million compared with net 2005 synfuel hedge mark-to-market gains of $47 million. In 2004, we recorded mark- to-market losses of $12 million. See Note 14 of the Notes to Consolidated Financial Statements.

(in Millions)

Components of Synfuel (Gains) Losses, Reserves and Impairments, Net	2006	2005	2004
Gains recognized associated with fixed payments	**$ (43)**	$ (132)	**$** (95)
Gains recognized associated with variable payments	**(14)**	(187)	(136)
Reserves recorded for contractual partners' obligations	**79**	—	—
Other reserves and impairments, including partners' share (1)	**78**	—	—
Hedge (gains) losses (mark-to-market)			
Hedges for 2005 exposure	**—**	(2)	12
Hedges for 2006 exposure	**(66)**	(40)	—
Hedges for 2007 exposure	**6**	(6)	—
	$ 40	$ (367)	**$** (219)

(1) Includes $70 million in 2006, representing our partners' share of the asset impairment, included in Minority Interest.

Minority interest decreased $67 million in 2006 and increased $95 million in 2005, reflecting our partners' share of operating losses associated with synfuel operations, as well as our partners' $70 million share of the asset impairment in 2006. 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 declined $105 million in 2006 and increased $33 million in 2005, reflecting changes in pre-tax income due to synfuel related loss reserves and the impairment of fixed assets, compared to pre-tax income in 2005.

Outlook – Due to the implementation of our hedging strategy, we expect to continue to operate the synfuel plants through December 31, 2007, when synfuel-related production tax credits expire.

CORPORATE & OTHER

Corporate & Other includes various corporate staff functions. As these functions 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 by $9 million in 2006 and declined $40 million in 2005. The 2006 decline was primarily due to higher Michigan Single Business Taxes. 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.

DISCONTINUED OPERATIONS

DTE Georgetown (Georgetown) — We own Georgetown, an 80 MW natural gas-fired peaking electric generating plant. In the fourth quarter of 2006, management approved the marketing of Georgetown for sale. In December 2006, Georgetown met the SFAS No. 144 criteria of an asset "held for sale" and we reported its operating results as a discontinued operation. We did not recognize an impairment loss since the carrying value of Georgetown's assets, less costs to sell approximated its fair value. In February 2007, we entered into an agreement to sell our Georgetown peaking electric generating facility. The sale is subject to receipt of regulatory approval and is expected to close in the second half of 2007.

DTE Energy Technologies (Dtech) - We own Dtech, which assembled, marketed, distributed and serviced distributed generation products, provided application engineering, and monitored and managed 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 generation sales and service. 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.

Southern Missouri Gas Company (SMGC) - We owned 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 (ITC) - In February 2003, we sold 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 4 of the Notes to Consolidated Financial Statements.

CUMULATIVE EFFECT OF ACCOUNTING CHANGES

Effective January 1, 2006, we adopted SFAS No. 123(R), *Share-Based Payment,* using the modified prospective transition method. The cumulative effect of the adoption of SFAS 123(R) was an increase in net income of $1 million as a result of estimating forfeitures for previously granted stock awards and performance shares.

In the fourth quarter of 2005, we adopted *FASB Interpretation FIN No. 47, Accounting for Conditional Asset Retirement Obligations, an interpretation of SFAS No. 143* that required additional new accounting rules for asset retirement obligations. The cumulative effect of adopting these new accounting rules reduced 2005 earnings by $3 million.

CAPITAL RESOURCES AND LIQUIDITY

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 2007 of up to $1.4 billion. The capital needs of our utilities will increase due primarily to environmental related expenditures. We may spend an additional $125 million on growth-related projects within our non-utility businesses in 2007.

Capital spending for general corporate purposes will increase in 2007, primarily as a result of environmental spending. We anticipate environmental expenditures of approximately $253 million in 2007 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 $300 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 2007 totals approximately $346 million.

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

(in Millions)	2006	2005	2004
Cash and Cash Equivalents			
Cash Flow From (Used For)			
Operating activities:			
Net income	**$ 433**	$ 537	$ 431
Depreciation, depletion and amortization	**1,014**	872	744
Deferred income taxes	**28**	147	129
Gain on sale of synfuel and other assets, net and synfuel impairment	**28**	(405)	(236)
Working capital and other	**(47)**	(150)	(73)
	1,456	1,001	995
Investing activities:			
Plant and equipment expenditures – utility	**(1,126)**	(850)	(815)
Plant and equipment expenditures – non-utility	**(277)**	(215)	(89)
Acquisitions, net of cash acquired	**(42)**	(50)	—
Proceeds from sale of synfuels and other assets	**313**	409	325
Restricted cash and other investments	**(62)**	(96)	(102)
	(1,194)	(802)	(681)
Financing activities:			
Issuance of long-term debt and common stock	**629**	1,041	777
Redemption of long-term debt	**(687)**	(1,266)	(759)
Short-term borrowings, net	**291**	437	33
Repurchase of common stock	**(61)**	(13)	—
Dividends on common stock and other	**(375)**	(366)	(363)
	(203)	(167)	(312)
Net Increase in Cash and Cash Equivalents	**$ 59**	$ 32	$ 2

Cash from Operating Activities

A majority of the Company's operating cash flow is provided by our electric and gas 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, primarily from the synthetic fuels business, which we believe, subject to considerations discussed below, will provide up to approximately $900 million of cash during 2007-2009.

Cash from operations totaling $1.5 billion in 2006 was up $455 million from the comparable 2005 period. The operating cash flow comparison reflects an increase of $352 million in net income, after adjusting for non-cash items (depreciation, depletion, amortization, deferred taxes and gains), and a $103 million decrease 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 a full year of higher rates granted in the 2004 rate orders and lower customer choice penetration. The working capital improvement was driven by MichCon which resulted primarily from declining GCR factors which had the effect of lowering customer accounts receivable balances. This improvement was partially offset by working capital requirements at Detroit Edison which resulted from pension and VEBA contributions totaling $271 million in 2006.

Cash from operations totaling $1.0 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 Energy Trading 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.

Outlook — We expect cash flow from operations to increase over the long-term primarily due to improvements from higher earnings at our utilities. We are incurring costs associated with implementation of our Performance Excellence Process, but we expect to realize sustained net cost savings beginning in 2007. 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 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 initiatives.

We anticipate approximately $900 million of synfuel-related cash impacts from 2007 through 2009, which consists of cash from operations and proceeds from option hedges, and approximately $500 million of tax credit carryforward utilization and other tax benefits that are expected to reduce future tax payments. The redeployment of this cash represents a unique opportunity to increase shareholder value and strengthen our balance sheet. We expect to use any such cash and the potential cash from monetization of certain of our non-utility assets and operations to reduce debt and repurchase common stock, and to continue to pursue growth investments that meet our strict risk-return and value creation criteria. We repurchased one million shares of common stock in December 2006. Our objectives for cash redeployment are to strengthen the balance sheet and coverage ratios to improve our current credit rating and outlook, and to have any monetization be accretive to earnings per share.

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 $392 million in 2006 compared to 2005. The 2006 change was primarily due to increased capital expenditures. The increase in capital expenditures was driven by environmental, Enterprise Business Systems development and distribution projects at Detroit Edison, pipeline reliability and inventory management projects at MichCon, and growth-oriented projects across our non-utility segments.

Net cash outflows relating to investing activities increased $121 million in 2005. The increase 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.

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% to 52%, 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 increased $36 million during 2006 compared to 2005, due mostly to a decrease in short-term borrowings and issuance of common stock and long-term debt, partially offset by a decrease in debt redemptions.

Net cash used for financing activities improved $145 million in 2005 due primarily to the issuance of common stock which resulted from the conversion of our equity security units.

See Notes 11 and 12 of the Notes to Consolidated Financial Statements.

In August 2006, DTE Energy and Detroit Edison filed a combined shelf registration statement for the issuance of securities in an unlimited amount for three years from its effective date. MichCon has a separate effective registration statement providing for the issuance of $200 million of securities.

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. We repurchased one million shares of our common stock in December 2006. 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, 2006:

(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	$ 6,163	$ 236	$ 1,124	$ 1,061	$ 3,742
Securitization bonds	1,295	111	391	314	479
Trust preferred-linked securities	289	—	—	—	289
Capital lease obligations	120	14	44	21	41
Interest	6,433	471	1,298	659	4,005
Operating leases	333	53	102	51	127
Electric, gas, fuel, transportation and storage purchase obligations (1)	6,249	3,007	2,437	135	670
Other long-term obligations	291	157	75	25	34
Total obligations	$ 21,173	$ 4,049	$ 5,471	$ 2,266	$ 9,387

(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 $383 million at December 31, 2006. 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.

		Credit Rating Agency		
Entity	Description	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)	$ (161)
MichCon	(46)
Total	$ (207)

(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 6 of the Notes to Consolidated Financial Statements.

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.

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, when probability of refund is considered remote 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 $295 million in 2006 as compared to $617 million in 2005, and $449 million in 2004. The portion of tax credits generated for our own account was $35 million in 2006, as compared to $55 million in 2005, and $38 million in 2004, 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, 2006, our goodwill totaled $2.1 billion. The majority of our goodwill is allocated to our utility reporting units. The value of the utility reporting units may be significantly impacted by rate orders and the regulatory environment.

We also have $4 million of goodwill allocated to the Synthetic Fuel reporting unit. The value of the Synthetic Fuel reporting unit has been impacted by the anticipated phase-out of tax credits. As of December 31, 2006, we have evaluated the impact of a phase-out of synfuel tax credits on our valuation assumptions. We have determined that the fair value of the Synthetic Fuel reporting unit exceeds the carrying value and no impairment of goodwill exists. These assumptions may change as the value of the synfuel tax credits change.

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

Based on our 2006 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 $125 million in 2006 (including Special Termination Benefits of $49 million), $90 million in 2005, and $81 million in 2004. Postretirement benefits costs for all plans were $197 million in 2006 (including Special Termination Benefits of $8 million), $155 million in 2005, and $125 million in 2004. Pension and postretirement benefits costs for 2006 are calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on our plan assets of 8.75%. 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 2007 expected long-term rate of return on plan assets is based on an asset allocation assumption utilizing active investment management of 65% in equity markets, 20% in fixed income markets, and 15% 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 2007. 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 gains due to the performance of the financial markets. As of December 31, 2006, we had $39 million of cumulative gains 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 5.9% at December 31, 2005 to 5.7% at December 31, 2006. Due to recent company contributions, financial market performance and lower discount rates, we estimate that our 2007 pension costs will approximate $66 million (excluding Special Termination Benefits) compared to $85 million (excluding Special Termination Benefits) in 2006 and our 2007 postretirement benefit costs will approximate $184 million compared to $189 million (excluding Special Termination Benefits of $8 million) in 2006. 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 2006 qualified pension costs by approximately $22 million. Lowering the discount rate and the salary increase assumptions by one-percentage-point would have increased our 2006 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 2006 by approximately $25 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 was $3.3 billion at December 31, 2004 and November 30, 2005. The value at November 30, 2006 was $3.5 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 2004 and 2005. At December 31, 2006, we adopted SFAS No. 158 that required us to recognize the underfunded status of our pension and other postretirement plans. The impact of the adoption of SFAS 158 was an increase in pension and postretirement benefit liabilities of approximately $1.3 billion. We requested and received agreement from the MPSC to record the additional liability amounts for the Detroit Edison and MichCon benefit plans on the Statement of Financial Position as a Regulatory asset. As a result, Regulatory assets were increased by approximately $1.2 billion. The remainder of the increase in pension and postretirement benefit liabilities is included in Accumulated Other Comprehensive Loss, net of tax.

Pension and postretirement costs and pension cash funding requirements may increase in future years without substantial returns in the financial markets. We made 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 and made a $180 million cash contribution in 2006. At the discretion of management, we anticipate making up to a $180 million contribution to our qualified pension plans in 2007 and up to $600 million over the next five years. Also, we anticipate making up to a $15 million contribution to our nonqualified benefit plans in 2007 and up to $35 million over the next five years. We contributed $80 million to our postretirement plans in 2004. We did not contribute to our postretirement plans in 2005 and made a $116 million contribution to our postretirement benefit plans in 2006. At the discretion of management, we anticipate making up to a $116 million contribution to our postretirement plans in 2007 and up to $580 million over the next five years.

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 $17 million in 2006, $20 million in 2005 and $16 million in 2004.

See Note 16 of the Notes to Consolidated Financial Statements.

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 2005 and 2006. 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 $875 million through 2006. We estimate Detroit Edison will incur future capital expenditures of up to $222 million in 2007 and up to $2 billion of additional capital expenditures through 2018 to satisfy both the existing and proposed new control requirements.

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.

We may also incur liabilities as a result of potential future requirements to address the climate change issue. There may be legislative action to address the issue of changes in climate that result from the build up of greenhouse gases, including carbon dioxide and methane, in the atmosphere. We cannot predict the impact any legislative action may have on the Company.

Water – In response to an EPA regulation, currently under judicial review, Detroit Edison may be 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. Initially, we estimated that we will incur up to approximately $53 million over the next three to five years in additional capital expenditures to comply with these requirements. However, a recent court decision remanded back to the EPA several provisions of the federal regulation which may result in a delay in compliance requirements. The court decision also raised the possibility that the Company may have to install cooling towers at some facilities. We cannot predict the effect on Detroit Edison of this court decision or any resulting regulations.

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 $11 million as of December 31, 2006 for the remediation of these sites over the next several years. In addition, Detroit Edison expects to make approximately $5 million of capital improvements to the ash landfill in 2007.

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 $41 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 2007.

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. After a study was completed in 1995, Gas Utility accrued an additional liability and a corresponding regulatory asset of $35 million. During 2006, we spent approximately $2 million investigating and remediating these former MGP sites. In December 2006, we retained multiple environmental consultants to estimate the project cost to remediate each MGP site. We accrued an additional $7 million in remediation liabilities associated with former MGP holders and additional cleanup cost, to increase the reserve balance to $41 million as of December 31, 2006.

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 facility in Michigan. We expect the project to be completed within one year. Our 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.

ENTERPRISE BUSINESS SYSTEMS

In 2003, we began the development of our Enterprise Business Systems (EBS) project, an enterprise resource planning 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 EBS 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. Additional phases of implementation are planned for 2007. The conversion of data and the implementation and operation of the EBS 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 $330 million through the end of 2006 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.

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;
- provides financial incentives for nuclear license applications completed by 2008;
- 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 3 of the Notes to Consolidated Financial Statements.

FAIR VALUE OF CONTRACTS

The following disclosures 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 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 2006:

(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, 2005	$ (108)	$ (136)	$ (110)	$ (354)	$ (140)	$ (494)
Reclassed to realized upon settlement	(21)	83	57	119	92	211
Liquidation of in-the-money positions (1)	—	—	(123)	(123)	—	(123)
Changes in fair value recorded to income	(5)	35	140	170	(6)	164
Amortization of option premiums	114	(2)	—	112	(40)	72
Amounts recorded to unrealized income	88	116	74	278	46	324
Amounts recorded in OCI	—	14	—	14	(3)	11
Option premiums paid and other	11	4	—	15	73	88
MTM at December 31, 2006	$ (9)	$ (2)	$ (36)	$ (47)	$ (24)	$ (71)

(1) In conjunction with our overall tax planning and cash initiatives, we monetized certain in-the-money contracts while simultaneously entering into at-the-market contracts with various counterparties. This had the impact of optimizing taxable income and cash flow while having minimal impact on earnings.

The following table provides a current and noncurrent analysis of "Assets and Liabilities from risk management and trading activities", as reflected on the Consolidated Statement of Financial Position as of December 31, 2006. 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	$ 62	$ 193	$ 108	$ (57)	$ 306	$ 155	$ 461
Noncurrent assets	7	55	108	(7)	163	1	164
Total MTM assets	69	248	216	(64)	469	156	625
Current liabilities	(71)	(189)	(132)	57	(335)	(102)	(437)
Noncurrent liabilities	(7)	(61)	(120)	7	(181)	(78)	(259)
Total MTM liabilities	(78)	(250)	(252)	64	(516)	(180)	(696)
Total MTM net assets (liabilities)	$ (9)	$ (2)	$ (36)	$ —	$ (47)	$ (24)	$ (71)

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**	2007	2008	2009	2010 and Beyond	Total Fair Value
Proprietary Trading	$ (9)	$ —	$ —	$ —	$ (9)
Structured Contracts	4	(6)	(4)	4	(2)
Economic Hedges	(24)	(8)	(4)	—	(36)
Total Energy Trading Activities	(29)	(14)	(8)	4	(47)
Other Non-Trading Activities	53	(61)	(16)	—	(24)
Total	$ 24	$ (75)	$ (24)	$ 4	$ (71)

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

DTE Energy has commodity price risk in both utility and non-utility businesses arising from market price fluctuations.

The Electric and Gas utility businesses have risks in conjunction with the anticipated purchases of coal, natural gas, uranium, electricity, and base metals to meet their service obligations. Further, changes in the price of electricity can impact the level of exposure of Customer Choice programs and uncollectible expenses at the Electric Utility. In addition, changes in the price of natural gas can impact the valuation of lost gas, storage sales revenue and uncollectible expenses at the Gas Utility.

To limit our exposure to commodity price fluctuations, the Utility businesses have applied various approaches to manage this risk. The approaches include forward energy, capacity, storage and futures contracts, as well as regulatory rate-recovery mechanisms. Regulatory rate-recovery occurs in the form of PSCR and GCR mechanisms (see Note 1 of the Notes to Consolidated Financial Statements) and a tracking mechanism to mitigate some losses from customer migration due to electric Customer Choice programs.

The non-utility businesses have risk in conjunction with electricity, natural gas, crude oil and coal.

Our Power and Industrial Projects and Synthetic Fuel segments are subject to crude oil, electricity, natural gas and coal based product 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. The benefits associated with tax credits may be subject to changes in federal tax law. Also, we have entered into a series of derivative contracts for 2007 to economically hedge the impact of oil prices on a portion of our synfuel cash flow. See Note 14 of the Notes to Consolidated Financial Statements. To limit our exposure to the other commodities we use forward energy, capacity and futures contracts.

Our Unconventional Gas Production business segment has exposure to natural gas and, to a lesser extent, crude oil price fluctuations. These commodity price fluctuations can impact both current year earnings and reserve valuations. To manage this exposure we use forward energy and futures contracts.

Our Energy Trading business segment has exposure to electricity, natural gas and crude oil price fluctuations. These risks are managed through its energy marketing and trading operations through the use of forward energy, capacity, storage and futures contracts, within pre-determined risk parameters.

Our Coal and Gas Midstream business segment has exposure to natural gas and coal price fluctuations. These coal price risks are managed primarily through its coal transportation and marketing operations through the use of forward coal and futures contracts. The Gas Midstream business unit manages its exposure through the sale of long-term storage and transportation contracts.

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.

Energy Trading

We are exposed to credit risk through trading activities. Credit risk is the potential loss that may result if our trading counterparties fail to meet their contractual 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, 2006:

(in Millions)	Credit Exposure before Cash Collateral	Cash Collateral	Net Credit Exposure
Investment Grade (1)			
A- and Greater	$ 526	$ (126)	$ 400
BBB+ and BBB	111	—	111
BBB-	107	—	107
Total Investment Grade	744	(126)	618
Non-investment grade (2)	68	—	68
Internally Rated — investment grade (3)	104	—	104
Internally Rated — non-investment grade (4)	9	(4)	5
Total	$ 925	$ (130)	$ 795

(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, a division of the McGraw-Hill Companies, Inc. (Standard & Poor's). The five largest counterparty exposures combined for this category represented 27% 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 7% 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 may 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, 2006, the Company has a floating rate debt to total debt ratio of approximately 18% (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 January 2011. 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, 2006 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	$ (10)	$ 11	Commodity contracts
Power Contracts	$ (17)	$ 17	Commodity contracts
Oil Contracts	$ 78	$ (62)	Commodity options
Interest Rate Risk	$ (314)	$ 339	Long-term debt
Foreign Currency Risk	$ 2	$ (2)	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, 2006, 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, 2006. 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, 2006, the Company's internal control over financial reporting was effective based on those criteria.

Our management's assessment of the effectiveness of the Company's internal control over financial reporting has been audited by the Company's independent auditors, 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, 2006.

There has been no change in the Company's internal control over financial reporting during the fourth quarter of 2006 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, 2006, 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, 2006, 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, 2006, 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, 2006 and for the year then ended, and the financial statement schedule; and our report dated March 1, 2007 expressed an unqualified opinion on those consolidated financial statements and financial statement schedule and included an explanatory paragraph regarding the Company's adoption of new accounting principles related to accounting for defined benefit pension and other postretirement plans and share based payments.

/S/ DELOITTE & TOUCHE LLP

Detroit, Michigan
March 1, 2007

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, 2006 and 2005, 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, 2006. 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, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 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 3 to the consolidated financial statements, in connection with the required adoption of new accounting principles, in 2006 the Company changed its method of accounting for defined benefit pension and other postretirement plans and share based payments. As discussed in Note 1 to the consolidated financial statements, in connection with the required adoption of a new accounting principle, in 2005 the Company changed its method of accounting for asset retirement obligations.

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, 2006, 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 1, 2007 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 1, 2007

DTE Energy Company
Consolidated Statement of Operations

(in Millions, Except per Share Amounts)	Year Ended December 31 2006	2005	2004
Operating Revenues	**$ 9,022**	$ 9,021	$ 7,069
Operating Expenses			
Fuel, purchased power and gas	**3,056**	3,530	2,007
Operation and maintenance	**3,696**	3,792	3,355
Depreciation, depletion and amortization	**1,014**	868	739
Taxes other than income	**321**	274	312
Asset (gains) and losses, reserves and impairments, net	**107**	(390)	(219)
	8,194	8,074	6,194
Operating Income	**828**	947	875
Other (Income) and Deductions			
Interest expense	**526**	519	516
Interest income	**(47)**	(57)	(55)
Other income	**(61)**	(68)	(81)
Other expenses	**86**	55	67
	504	449	447
Income Before Income Taxes and Minority Interest	**324**	498	428
Income Tax Provision (Note 9)	**137**	202	176
Minority Interest	**(250)**	(281)	(212)
Income from Continuing Operations	**437**	577	464
Loss from Discontinued Operations, net of tax (Note 4)	**(5)**	(37)	(33)
Cumulative Effect of Accounting Changes, net of tax (Notes 1, 3 and 17)	**1**	(3)	—
Net Income	**$ 433**	$ 537	$ 431
Basic Earnings per Common Share (Note 10)			
Income from continuing operations	**$ 2.46**	$ 3.30	$ 2.69
Discontinued operations	**(.03)**	(.21)	(.19)
Cumulative effect of accounting changes	**.01**	(.02)	—
Total	**$ 2.44**	$ 3.07	$ 2.50
Diluted Earnings per Common Share (Note 10)			
Income from continuing operations	**$ 2.45**	$ 3.28	$ 2.68
Discontinued operations	**(.03)**	(.21)	(.19)
Cumulative effect of accounting changes	**.01**	(.02)	—
Total	**$ 2.43**	$ 3.05	$ 2.49
Average Common Shares			
Basic	**177**	175	173
Diluted	**178**	176	173
Dividends Declared per Common Share	**$ 2.075**	$ 2.06	$ 2.06

See Notes to Consolidated Financial Statements

DTE Energy Company
Consolidated Statement of Financial Position

(in Millions)	December 31 2006	December 31 2005
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 147**	$ 88
Restricted cash (Note 1)	**146**	122
Accounts receivable (less allowance for doubtful accounts of $170 and $136, respectively)		
Customer	**1,427**	1,746
Collateral held by others	**68**	286
Other	**442**	363
Accrued power and gas supply cost recovery revenue	**117**	186
Inventories		
Fuel and gas	**562**	522
Materials and supplies	**153**	146
Deferred income taxes	**245**	257
Assets from risk management and trading activities	**461**	806
Other	**193**	160
	3,961	4,682
Investments		
Nuclear decommissioning trust funds	**740**	646
Other	**505**	530
	1,245	1,176
Property		
Property, plant and equipment	**19,224**	18,660
Less accumulated depreciation and depletion (Note 1)	**(7,773)**	(7,830)
	11,451	10,830
Other Assets		
Goodwill	**2,057**	2,057
Regulatory assets (Note 6)	**3,226**	2,074
Securitized regulatory assets (Note 6)	**1,235**	1,340
Intangible assets	**72**	99
Notes receivable	**164**	409
Assets from risk management and trading activities	**164**	316
Prepaid pension assets	**71**	186
Other	**139**	166
	7,128	6,647
Total Assets	**$ 23,785**	$ 23,335

See Notes to Consolidated Financial Statements

DTE Energy Company
Consolidated Statement of Financial Position

(in Millions, Except Shares)	December 31 2006	2005
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	**$ 1,145**	$ 1,187
Accrued interest	**115**	115
Dividends payable	**94**	92
Short-term borrowings	**1,131**	943
Current portion long-term debt, including capital leases	**354**	691
Liabilities from risk management and trading activities	**437**	1,089
Other	**888**	803
	4,164	4,920
Other Liabilities		
Deferred income taxes	**1,465**	1,396
Regulatory liabilities (Notes 1 and 6)	**765**	715
Asset retirement obligations (Notes 1 and 7)	**1,221**	1,091
Unamortized investment tax credit	**120**	131
Liabilities from risk management and trading activities	**259**	527
Liabilities from transportation and storage contracts	**157**	317
Accrued pension liability	**388**	284
Accrued postretirement liability	**1,414**	406
Deferred gains from asset sales	**36**	188
Minority interest	**42**	92
Nuclear decommissioning (Note 7)	**119**	85
Other	**312**	334
	6,298	5,566
Long-Term Debt (net of current portion) (Notes 11 and 13)		
Mortgage bonds, notes and other	**5,918**	5,234
Securitization bonds	**1,185**	1,295
Equity-linked securities	**—**	175
Trust preferred-linked securities	**289**	289
Capital lease obligations	**82**	87
	7,474	7,080
Commitments and Contingencies (Notes 2, 6, 7 and 15)		
Shareholders' Equity		
Common stock, without par value, 400,000,000 shares authorized, 177,138,060 and 177,814,429 shares issued and outstanding, respectively	**3,467**	3,483
Retained earnings	**2,593**	2,557
Accumulated other comprehensive loss	**(211)**	(271)
	5,849	5,769
Total Liabilities and Shareholders' Equity	**$ 23,785**	$ 23,335

See Notes to Consolidated Financial Statements

DTE Energy Company
Consolidated Statement of Cash Flows

(in Millions)	Year Ended December 31 2006	2005	2004
Operating Activities			
Net income	**$ 433**	$ 537	$ 431
Adjustments to reconcile net income to net cash from operating activities:			
Depreciation, depletion and amortization	**1,014**	872	744
Deferred income taxes	**28**	147	129
Gain on sale of assets, net	**(11)**	(38)	(17)
Gain on sale of interests in synfuel projects	**(38)**	(367)	(219)
Impairment of synfuel projects	**77**	—	—
Partners' share of synfuel project losses	**(251)**	(318)	(223)
Contributions from synfuel partners	**197**	243	141
Cumulative effect of accounting changes	**(1)**	3	—
Changes in assets and liabilities, exclusive of changes shown separately (Note 1)	**8**	(78)	9
Net cash from operating activities	**1,456**	1,001	995
Investing Activities			
Plant and equipment expenditures – utility	**(1,126)**	(850)	(815)
Plant and equipment expenditures – non-utility	**(277)**	(215)	(89)
Acquisitions, net of cash acquired	**(42)**	(50)	—
Proceeds from sale of interests in synfuel projects	**246**	349	221
Proceeds from sale of assets, net	**67**	60	104
Restricted cash for debt redemptions	**(21)**	4	5
Proceeds from sale of nuclear decommissioning trust fund assets	**253**	201	254
Investment in nuclear decommissioning trust funds	**(284)**	(235)	(287)
Other investments	**(10)**	(66)	(74)
Net cash used for investing activities	**(1,194)**	(802)	(681)
Financing Activities			
Issuance of long-term debt	**612**	869	736
Redemption of long-term debt	**(687)**	(1,266)	(759)
Short-term borrowings, net	**291**	437	33
Issuance of common stock	**17**	172	41
Repurchase of common stock	**(61)**	(13)	—
Dividends on common stock	**(365)**	(360)	(354)
Other	**(10)**	(6)	(9)
Net cash used for financing activities	**(203)**	(167)	(312)
Net Increase in Cash and Cash Equivalents	**59**	32	2
Cash and Cash Equivalents at Beginning of Period	**88**	56	54
Cash and Cash Equivalents at End of Period	**$ 147**	$ 88	$ 56

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, 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 16)	—	—	—	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 16)	—	—	—	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
Net income	**—**	**—**	**433**	**—**	**433**
Issuance of new shares	**411**	**17**	**—**	**—**	**17**
Dividends declared on common stock	**—**	**—**	**(368)**	**—**	**(368)**
Repurchase and retirement of common stock	**(1,283)**	**(32)**	**(29)**	**—**	**(61)**
Adjustment to initially apply SFAS No. 158 (net of tax) (Note 16)	**—**	**—**	**—**	**(38)**	**(38)**
Pension obligations (Note 16)	**—**	**—**	**—**	**3**	**3**
Net change in unrealized losses on derivatives, net of tax	**—**	**—**	**—**	**102**	**102**
Net change in unrealized losses on investments, net of tax	**—**	**—**	**—**	**(7)**	**(7)**
Unearned stock compensation and other	**196**	**(1)**	**—**	**—**	**(1)**
Balance, December 31, 2006	**177,138**	**$ 3,467**	**$ 2,593**	**$ (211)**	**$ 5,849**

The following table displays comprehensive income:

(in Millions)	**2006**	2005	2004
Net income	**$ 433**	$ 537	$ 431
Other comprehensive income (loss), net of tax:			
Pension obligations, net of taxes of $2, $2 and $4 (Notes 6 and 16)	**3**	4	7
Net unrealized gains (losses) on derivatives:			
Gains (losses) arising during the period, net of taxes of $3, $(78) and $(26)	**6**	(145)	(49)
Amounts reclassified to income, net of taxes of $52, $21 and $18	**96**	39	34
	102	(106)	(15)
Net unrealized losses on investments:			
Losses arising during the period, net of taxes of $(4), $(3) and $(3)	**(7)**	(6)	(5)
Amounts reclassified to income, net of taxes of $-, $(2) and $(8)	**—**	(5)	(15)
	(7)	(11)	(20)
Comprehensive income	**$ 531**	$ 424	$ 403

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 coal transportation and marketing, and gas storage and transportation, natural gas exploration and production, power and industrial projects, energy marketing and trading and synthetic fuel.

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," "Company" or "DTE" 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.*

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.

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. See Note 6.

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

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, 2006 include: unrealized gains and losses from derivatives accounted for as cash flow hedges, unrealized gains and losses on available for sale securities, minimum pension liabilities and pension and postretirement costs. As a result of the adoption of SFAS No. 158 effective December 31, 2006, the minimum pension liability is no longer recognized. Pension and postretirement costs consisting of deferred actuarial losses, prior service costs and transition amounts related to the pension and postretirement plans were recorded pursuant to SFAS No. 158.

(in Millions)	Net Unrealized Losses on Derivatives	Net Unrealized Gains on Investments	Pension and Postretirement Obligations	Accumulated Other Comprehensive Loss
Beginning balances	$ (206)	$ 22	$ (87)	$ (271)
Current-period change	102	(7)	3	98
Adjustment to initially apply SFAS No. 158 (net of tax)	—	—	(38)	(38)
Ending balance	$ (104)	$ 15	$ (122)	$ (211)

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, 2006, the replacement cost of gas remaining in storage exceeded the $77 million LIFO cost by $236 million. During 2006, MichCon liquidated 5.1 billion cubic feet of prior years' LIFO layers. The liquidation reduced 2006 cost of gas by approximately $1 million, but had no impact on earnings as a result of the GCR mechanism. At December 31, 2005, the replacement cost of gas remaining in storage exceeded the $119 million LIFO cost by $496 million. During 2004, MichCon liquidated 5.7 billion cubic feet of prior years' LIFO layers. The liquidation reduced 2004 cost of gas by approximately $7 million, but had no impact on earnings as a result of the GCR mechanism.

Our Energy Trading 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)	2006	2005
Property, Plant and Equipment		
Electric Utility		
Generation	$ 7,667	$ 7,375
Distribution	6,249	6,041
Total Electric Utility	13,916	13,416
Gas Utility		
Distribution	2,175	2,098
Storage	245	237
Other	985	929
Total Gas Utility	3,405	3,264
Non-utility and Other	1,903	1,980
Total Property, Plant and Equipment	19,224	18,660
Less Accumulated Depreciation and Depletion		
Electric Utility		
Generation	(3,410)	(3,439)
Distribution	(2,170)	(2,156)
Total Electric Utility	(5,580)	(5,595)
Gas Utility		
Distribution	(926)	(891)
Storage	(108)	(104)
Other	(513)	(481)
Total Gas Utility	(1,547)	(1,476)
Non-utility and Other	(646)	(759)
Total Accumulated Depreciation and Depletion	(7,773)	(7,830)
Net Property, Plant and Equipment	$ 11,451	$ 10,830

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 value, 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 $16 million of expenses related to the anticipated Fermi 2 refueling outage scheduled for 2007 were accrued at December 31, 2006. Amounts are being accrued on a pro-rata basis over an 18-month period that began in May 2006. 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 matches the regulatory recovery of these costs in rates set by the MPSC. See Note 3.

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 3.3% in 2006, 3.4% in 2005 and 2004. The composite depreciation rate for MichCon was 2.8%, 3.2% and 3.6% in 2006, 2005, and 2004, respectively.

The average estimated useful life for each major class of utility property, plant and equipment as of December 31, 2006 follows:

	Estimated Useful Lives in Years		
Utility	Generation	Distribution	Transmission
Electric	40	37	N/A
Gas	N/A	37	40

Non-utility property is depreciated over its estimated useful life using straight-line, declining-balance or units-of-production methods. The estimated useful lives for major classes of non-utility assets and facilities ranges from 20 to 40 years.

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.

Intangible assets relating to capitalized software are classified as Property, Plant and Equipment and the related amortization is included in Accumulated Depreciation and Depletion on the Consolidated Statement of Financial Position. 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 5 to 20 years. Intangible assets amortization expense was $37 million in 2006, $41 million in 2005 and $43 million in 2004. The gross carrying amount and accumulated amortization of intangible assets at December 31, 2006 were $503 million and $108 million, respectively. The gross carrying amount and accumulated amortization of intangible assets at December 31, 2005 were $470 million and $168 million, respectively. Amortization expense of intangible assets is estimated to be $46 million annually for 2007 through 2011.

Asset Retirement Obligations

We have recorded asset retirement obligations in accordance with SFAS No. 143, *Accounting for Asset Retirement Obligations* and FASB Interpretation FIN No. 47, *Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143*. We have a legal retirement obligation for the decommissioning costs for our Fermi 1 and Fermi 2 nuclear plants. To a lesser extent, we have legal retirement obligations for the synthetic fuel operations, gas production facilities, gas gathering facilities and various other operations. We have 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 disposal costs for PCB contained within transformers and circuit breakers.

For our regulated operations, the adoptions of SFAS No. 143 and FIN 47 resulted primarily in timing differences in the recognition of legal asset retirement costs that we are currently recovering in rates. We defer 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 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.

No liability has been recorded with respect to lead-based paint, as the quantities of lead-based paint in our facilities 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 asset retirement liability has been recorded for these assets.

A reconciliation of the asset retirement obligations for 2006 follows:

(in Millions)	
Asset retirement obligations at January 1, 2006	$ 1,091
Accretion	72
Liabilities incurred	6
Liabilities settled	(7)
Revision in estimated cash flows	59
Asset retirement obligations at December 31, 2006	$ 1,221

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.

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

We have certain intangible assets relating to non-utility contracts and emission allowances. We amortize intangible assets on a straight-line basis over the expected period of benefit, ranging from 5 to 26 years. Intangible assets amortization expense was $5 million in 2006, $2 million in 2005 and $1 million in 2004. The gross carrying amount and accumulated amortization of intangible assets at December 31, 2006 were $80 million and $8 million, respectively. The gross carrying amount and accumulated amortization of intangible assets at December 31, 2005 were $102 million and $3 million, respectively. Amortization expense of intangible assets is estimated to be $5 million annually for 2007 through 2011.

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.

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. Our investments are reviewed for impairment each reporting period. If the assessment indicates that the impairment is other than temporary, a loss is recognized resulting in the investment being written down to its estimated fair value. See Note 7.

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)	2006	2005	2004
Changes in Assets and Liabilities, Exclusive of Changes Shown Separately			
Accounts receivable, net	**$ 441**	$ (633)	$ 11
Accrued GCR revenue	**120**	(16)	(35)
Inventories	**(49)**	(6)	(40)
Recoverable pension and postretirement costs	**(1,184)**	61	(20)
Accrued/Prepaid pensions	**218**	17	88
Accounts payable	**(68)**	290	266
Accrued PSCR refund	**(101)**	(127)	112
Exchange gas payable	**—**	5	(43)
Income taxes payable	**46**	(38)	(170)
General taxes	**3**	(11)	(14)
Risk management and trading activities	**(518)**	353	(64)
Postretirement obligation	**1,008**	132	29
Other assets	**(134)**	(9)	75
Other liabilities	**226**	(96)	(186)
	$ 8	$ (78)	$ 9

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

(in Millions)	2006	2005	2004
Cash Paid for:			
Interest (excluding interest capitalized)	**$526**	$516	$517
Income taxes	**$ 89**	$ 80	$ 203
Noncash Investing and Financing Activities			
Notes received from sale of synfuel projects	**$ —**	$ 20	$ 214
Common stock contribution to pension plan	**$ —**	$ —	$ 170
Sale of assets			
Note receivable	**$ —**	$ 47	$ —
Other assets	**$ —**	$ 45	$ —

We entered into a margin loan facility with an affiliate of the clearing agent of a commodity exchange in lieu of posting additional cash collateral (a non-cash transaction). The amount outstanding under the Facility was $103 million as of December 31, 2005. In October 2006, we changed our clearing agent and entered into a new demand financing agreement for up to $150 million. The amount outstanding under this new agreement was $23 million at December 31, 2006. See Note 12.

In October 2006, we purchased the lessor interest in the 66 Bcf Washington 10 gas storage field. Prior to the purchase, we leased the storage rights and lease obligations which were recorded as operating leases. The acquisition resulted in a cash payment of approximately $13 million and the assumption of approximately $133 million of project related debt that was recorded on our Consolidated Statement of Financial Position. See Note 11.

Asset (gains) and losses, reserves and impairments, net

The following items are included in the Asset (gains) and losses, reserves and impairments, net line in the Consolidated Statement of Operations:

(in Millions)

Description	2006	2005	2004
Synfuel (Gains) Losses, Reserves and Impairments			
Gains recognized for fixed payments	$ **(43)**	$ (132)	$ (95)
Gains recognized for variable payments	**(14)**	(187)	(136)
Reserves for contractual partners' obligations	**79**	—	—
Other reserves and impairments, including partners' share	**78**	—	—
Hedges (mark-to-market)	**(60)**	(48)	12
Synfuels (net)	**40**	(367)	(219)
Other Non-utility impairments:			
Waste coal recovery	**19**	—	—
Landfill gas recovery	**14**	—	—
Power generation	**42**	—	—
	75	—	—
Electric utility sale of land	**(6)**	(26)	—
Other	**(2)**	3	—
	$ 107	$ (390)	$ (219)

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

Note	Title
3	New Accounting Pronouncements
6	Regulatory Matters
9	Income Taxes
14	Financial and Other Derivative Instruments
16	Retirement Benefits and Trusteed Assets
17	Stock-based Compensation

NOTE 2 – SYNFUEL OPERATIONS

Synthetic Fuel Operations

We are the operator of nine synthetic fuel production facilities throughout the United States. 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. Through December 31, 2006, we have generated and recorded approximately $580 million in 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 significant market incentives for the production of 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. We project the yearly average wellhead price per barrel of oil for the year to be approximately $6 lower than the New York Mercantile Exchange (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 $55 per barrel and would be completely phased out if the Reference Price reached $69 per barrel. As of December 31, 2006, the realized NYMEX daily closing price of a barrel of oil was approximately $66 for 2006, equating to an estimated Reference Price of $60, which we estimate to be within the phase-out range.

To mitigate the effect of a potential phase-out and minimize operating losses we idled production at all nine of the synthetic fuel facilities that we operate on May 12, 2006. The decision to idle synfuel production was driven by the level and volatility of oil prices at that time. During the idle period, we took various steps to reduce our oil price exposure, including, renegotiation of a significant number of commercial agreements. Beginning September 5, 2006 through October 4, 2006, we resumed production at each of the nine synfuel facilities due to these amended commercial agreements and declines in the level of oil prices.

Gains (Losses) from Sale of Interests in Synthetic Fuel Facilities

Through December 2006, we have sold interests in all of the 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. 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 a pre-tax loss of $40 million in 2006 and pre-tax gains of $367 million and $219 million in 2005 and 2004, respectively, from the sale of interests in synthetic fuel facilities, net of reserves and impairments.

The gain from the sale of synfuel facilities is comprised of fixed and variable components. The fixed component represents note payments, 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 and is subject to refund based on the annual oil price phase-out. The variable component is recognized as a gain only when the probability of refund is considered remote and collectibility is assured. Additionally, our partners reimburse us (through the project entity) for the operating losses of the synfuel facilities, referred to as capital contributions. In the event that the tax credit is phased out, we are contractually obligated to refund an amount equal to all or a portion of the operating losses funded by our partners. To assess the probability and estimate the amount of refund, we use valuation and analysis models that calculate the probability of the Reference Price of oil for the year being within or exceeding the phase-out range. We recorded reserves for contractual partners' obligations of $79 million in 2006.

Derivative Instruments - Commodity Price Risk

To manage our exposure to the risk of an increase in oil prices that could substantially 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' average NYMEX trading prices for light, sweet crude oil in relation to the strike prices of each option. These contracts are based on various terms to take advantage of favorable oil price movements. The agreements do not qualify for hedge accounting, therefore, the changes in the fair value of the options are recorded currently in earnings. The fair value changes shown below are recorded as adjustments to the gain from selling interests in synfuel facilities and are included in the Asset gains and losses, reserves and impairments, net line item in the Consolidated Statement of Operations.

(in Millions)	**2006**	2005	2004
Hedge (gains) losses (mark-to-market)			
Hedges for 2005 exposure	**$ —**	$ (2)	**$** 12
Hedges for 2006 exposure	**(66)**	(40)	—
Hedges for 2007 exposure	**6**	(6)	—
	$ (60)	$ (48)	**$** 12

Impairments and Reserves

In 2006, we determined that certain assets related to our synfuel operations were impaired. The decision to record an impairment was based on the level and volatility of oil prices and the ability of the synfuel operations to generate production tax credits. In 2006, we recorded a pre-tax loss of $157 million within the Asset (gains) and losses, reserves and impairments, net, line item in the Consolidated Statement of Operations. The loss consists of two components; $78 million for synfuel related fixed asset impairment and inventory write-down and $79 million for a reserve for capital contributions related to operating losses. We based the impairment decision on an analysis of the undiscounted cash flows from the use and eventual disposition of the assets and determined that the carrying amount of the assets exceeded their expected fair value. The income impact of the fixed asset impairment and inventory write-down was partially offset by $70 million, representing our partners' share of the asset write down, included in the Minority Interest line in the Consolidated Statement of Operations.

Guarantees

We have provided certain guarantees and indemnities in conjunction with the sales of interests in our synfuel facilities. The guarantees cover potential commercial, environmental, oil price and tax-related obligations and will survive until 90 days after expiration of all applicable statute of limitations. We estimate that our maximum potential liability under these guarantees at December 31, 2006 is $2.4 billion. At December 31, 2006, we have reserved $181 million of our maximum potential liability primarily representing the possible refund of certain payments made by our synfuel partners.

NOTE 3 – NEW ACCOUNTING PRONOUNCEMENTS

Accounting for Uncertainty in Income Taxes

In July 2006, the FASB issued Financial Interpretation No. 48 (FIN 48), *Accounting for Uncertainty in Income Taxes – An Interpretation of FASB Statement No. 109 – Accounting for Income Taxes.* FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FASB Statement No. 109. Additionally, it prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in the tax return. FIN 48 provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition and is effective for fiscal years beginning after December 15, 2006. We plan to adopt FIN 48 effective January 1, 2007. We do not expect the adoption to have a material impact to the January 1, 2007 balance of retained earnings.

Fair Value Accounting

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements.* SFAS 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles, and expands disclosures about fair value measurements. It emphasizes that fair value is a market-based measurement, not an entity-specific measurement. Fair value measurement should be determined based on the assumptions that market participants would use in pricing an asset or liability. SFAS 157 is effective for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. We plan to adopt SFAS 157 on January 1, 2008. We are currently assessing the effects of this statement, and have not yet determined the impact on the consolidated financial statements.

In February 2007, the FASB issued SFAS 159, *The Fair Value Option for Financial Assets and Financial Liabilities - Including an Amendment of FASB Statement No. 115.* This standard permits an entity to choose to measure many financial instruments and certain other items at fair- value. The fair value option established by SFAS 159 permits all entities to choose to measure eligible items at fair value at specified election dates. An entity will report unrealized gains and losses on items for which the fair value option has been elected in earnings at each subsequent reporting date. The fair value option: (a) may be applied instrument by instrument, with a few exceptions, such as investments otherwise accounted for by the equity method; (b) is irrevocable (unless a new election date occurs); and (c) is applied only to entire instruments and not to portions of instruments. SFAS 159 is effective as of the beginning of an entity's first fiscal year that begins after November 15, 2007. We are currently assessing the effects of this statement, and have not yet determined the impact on the consolidated financial statements.

Accounting for Defined Benefit Pension and Other Postretirement Plans

In September 2006, the FASB issued SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans — an Amendment of FASB Statements No. 87, 88, 106, and 132(R).* SFAS 158 requires companies to (1) recognize the overfunded or underfunded status of defined benefit pension and defined benefit other postretirement plans in its financial statements, (2) recognize as a component of other comprehensive income, net of tax, the actuarial gains or losses and the prior service costs or credits that arise during the period but are not immediately recognized as components of net periodic benefit cost, (3) recognize adjustments to other comprehensive income when the actuarial gains or losses, prior service costs or credits, and transition assets or obligations are recognized as components of net periodic benefit cost, (4) measure postretirement benefit plan assets and plan obligations as of the date of the employer's statement of financial position, and (5) disclose additional information in the notes to financial statements about certain effects on net periodic benefit cost in the upcoming fiscal year that arise from delayed recognition of the actuarial gains and losses and the prior service cost and credits.

The requirement to recognize the funded status of a defined benefit pension or defined benefit other postretirement plan and the related disclosure requirements was effective for fiscal years ending after December 15, 2006, and we adopted this portion of the standard on December 31, 2006. We requested and received agreement from the MPSC to record the additional liability amounts for Detroit Edison and MichCon on the balance sheet as a regulatory asset.

The requirement to measure plan assets and benefit obligations as of the date of the employer's fiscal year-end statement of financial position is effective for fiscal years ending after December 15, 2008. The Statement provides two options for the transition to a fiscal year end measurement date. We currently use a November 30 measurement date. We have not yet determined which of the available transition measurement options we will use.

See Note 16.

Accounting for Planned Major Maintenance

In September 2006, the FASB issued its Staff Position (FSP), AUG AIR-1, *Accounting for Planned Major Maintenance Activities.* This FSP prohibits the use of the accrue-in-advance method of accounting for planned major maintenance activities in annual and interim financial reporting periods. We have historically charged expenditures for maintenance and repairs to expense as they were incurred, with the exception of Fermi 2, where we have utilized the accrue-in-advance policy for nuclear refueling outage costs since the plant was placed in service in 1988. We adopted this FSP on December 31, 2006. Although this FSP prohibits use of the accrue-in-advance method, we will continue to use it to account for the cost of Fermi 2 refueling outages because it matches the regulatory recovery of these costs in rates set by the MPSC and, therefore is in compliance with the requirements of SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation.* The adoption of FSP AUG AIR-1 had no income impact on our financial statements. See Note 6.

Quantifying Misstatements

In September 2006, the SEC staff issued Staff Accounting Bulletin (SAB) Topic 1N, *Financial Statements — Considering the Effects of Prior Year Misstatements When Quantifying Misstatements in Current Year Financial Statements* (SAB 108). SAB 108 addresses how a registrant should quantify the effect of an error on the financial statements. The SEC staff concluded in SAB 108 that a dual approach should be used to compute the amount of a misstatement. Specifically, the amount should be computed using both the "rollover" (current year income statement perspective) and "iron curtain" (year-end balance sheet perspective) methods. We adopted this SAB effective December 31, 2006. Based on our assessment we identified no errors that would require an adjustment to current or prior financial statements; therefore, the adoption of SAB 108 had no financial statement impact.

Stock Based Compensation

We adopted SFAS No. 123(R), *Share Based Payments* effective January 1, 2006. Previously we had been following the recognition and measurement principles of Accounting Principles Board (APB) No. 25, *Accounting for Stock Issued to Employees*, and followed the nominal vesting period approach for awards with retirement eligibility provisions. See Note 17 for the effects of the adoption of SFAS No. 123(R).

NOTE 4 – DISCONTINUED OPERATIONS

DTE Georgetown (Georgetown)

We own Georgetown, an 80 MW natural gas-fired peaking electric generating plant. In the fourth quarter of 2006, management approved the marketing of Georgetown for sale. In December 2006, Georgetown met the SFAS No. 144 criteria of an asset "held for sale" and we reported its operating results as a discontinued operation. We did not recognize an impairment loss since the net book value of Georgetown's assets, less costs to sell approximated its fair value. As of December 31, 2006, Georgetown's assets are $23 million and its liabilities are $1 million. In February 2007, we entered into an agreement to sell our Georgetown peaking electric generating facility. The sale is subject to receipt of regulatory approval and is expected to close in the second half of 2007.

As shown in the following table, we have reported the business activity of Georgetown as a discontinued operation. The amounts exclude general corporate overhead costs:

	Year Ended December 31		
(in Millions)	**2006**	2005	2004
Revenues (1)	**$ 1**	$ 1	$ 2
Expenses	**3**	2	7
Loss before income taxes	**(2)**	(1)	(5)
Income tax benefit	**—**	—	(2)
Loss from discontinued operations	**$ (2)**	$ (1)	$ (3)

(1) Includes intercompany revenues of $1 million for 2006, 2005 and 2004.

DTE Energy Technologies (Dtech)

We own Dtech, which assembled, marketed, distributed and serviced distributed generation products, provided application engineering, and monitored and managed 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 generation sales and service. The systems monitoring business is planned to be retained by the Company.

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. At December 31, 2006, Dtech had liabilities of $3 million.

As shown in the following table, we have reported the business activity of Dtech as a discontinued operation. The amounts exclude general corporate overhead costs and operations that are to be retained. We expect continued legal and warranty expenses in 2007 related to Dtech's operations prior to July 2005.

	Year Ended December 31		
(in Millions)	**2006**	2005	2004
Revenues (1)	**$ 1**	$ 18	$ 43
Expenses	**6**	67	70
Loss before income taxes	**(5)**	(49)	(27)
Income tax benefit	**(2)**	(14)	(9)
Loss from discontinued operations	**$ (3)**	$ (35)	$ (18)

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

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 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.

NOTE 5 – OTHER IMPAIRMENTS AND RESTRUCTURING

Other Impairments

Waste Coal Recovery

In 2006, our Power and Industrial Projects segment impaired its investment in proprietary technology used to refine waste coal. The fixed assets at our development operation were impaired due to continued operating losses and negative cash flow. In addition, we impaired all our patents related to waste coal technology. We calculated the expected undiscounted cash flows from the use and eventual disposition of the assets, which indicated that the carrying amount of the assets was not recoverable. We determined the fair value of the assets utilizing a discounted cash flow technique. Through December 31, 2006, we have recorded a pre-tax impairment loss of $19 million within the Asset (gains) and losses, reserves and impairments, net line in the Consolidated Statement of Operations.

Landfill Gas Recovery

In 2006, our Power and Industrial Projects segment recorded a pre-tax impairment loss of $14 million at our landfill gas recovery unit relating to the write-down of assets at several landfill sites. The fixed assets were impaired due to continued operating losses and the oil price-related phase-out of production tax credits. The impairment was recorded within the Asset (gains) and losses, reserves and impairments, net line in the Consolidated Statement of Operations. We calculated the expected undiscounted cash flows from the use and eventual disposition of the assets, which indicated that the carrying amount of certain assets was not recoverable. We determined the fair value of the assets utilizing a discounted cash flow technique.

Non-Utility Power Generation

In 2006, our Power and Industrial Projects segment recorded a pre-tax impairment loss totaling $74 million for its investments in two natural gas-fired electric generating plants.

A loss of $42 million related to a 100% owned plant is recorded within the Asset (gains) and losses, reserves and impairments, net line in the Consolidated Statement of Operations. The generating plant was impaired due to continued operating losses and the September 2006 delisting by MISO, resulting in the plant no longer providing capacity for the power grid. We calculated the expected undiscounted cash flows from the use and eventual disposition of the plant, which indicated that the carrying amount of the plant was not recoverable. We determined the fair value of the plant utilizing a discounted cash flow technique.

A loss of $32 million related to a 50% equity interest in a peaking, gas-fired electric generating plant is recorded within the Other (income) and deductions, other expenses line in the Consolidated Statement of Operations. The investment was impaired due to continued operating losses and the expected sale of the investment. We determined the fair value of the plant utilizing a discounted cash flow technique, which indicated that the carrying amount of the investment exceeded its fair value.

Restructuring – Performance Excellence Process

In mid-2005, we initiated a company-wide review of our operations called the Performance Excellence Process. Specifically, we began a series of focused improvement initiatives within our Electric and Gas Utilities, and associated corporate support functions. We expect this process will be carried out over a two to three year period beginning in 2005.

We have incurred CTA for employee severance and other costs. Other costs include project management and consultant support. Pursuant to MPSC authorization, in 2006, Detroit Edison deferred approximately $102 million of CTA. Detroit Edison will begin amortizing deferred 2006 costs in 2007 as the recovery of these costs was provided for by the MPSC. MichCon cannot defer CTA costs at this time because a recovery mechanism has not been established. See Note 6.

Amounts expensed are recorded in the Operation and maintenance line on the Consolidated Statement of Operations. Deferred amounts are recorded in the Regulatory asset line on the Consolidated Statement of Financial Position. Expenses incurred in 2006 are as follows:

(in Millions) Business Segment	Employee Severance Costs	Other Costs	Total Costs
Costs incurred:			
Electric Utility	$ 51	$ 56	$ 107
Gas Utility	17	7	24
Other	2	1	3
Total costs	70	64	134
Less amounts deferred or capitalized:			
Electric Utility	51	56	107
Amounts expensed	$ 19	$ 8	$ 27

A liability for future CTA associated with the Performance Excellence Process has not been recognized because we have not met the recognition criteria of SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities* .

NOTE 6 – 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)	2006	2005
Assets		
Securitized regulatory assets	**$ 1,235**	$ 1,340
Recoverable income taxes related to securitized regulatory assets	**$ 677**	$ 734
Recoverable pension and postretirement costs	**1,728**	544
Asset retirement obligation	**236**	196
Other recoverable income taxes	**100**	104
Recoverable costs under PA 141		
Net stranded costs	**—**	112
Excess capital expenditures	**22**	22
Deferred Clean Air Act expenditures	**67**	82
Midwest Independent System Operator charges	**48**	56
Electric Customer Choice implementation costs	**78**	98
Enhanced security costs	**13**	13
Unamortized loss on reacquired debt	**69**	73
Deferred environmental costs	**40**	34
Accrued PSCR/GCR revenue	**117**	186
Recoverable uncollectibles expense	**45**	11
Cost to achieve Performance Excellence Process	**102**	—
Enterprise Business Systems costs	**9**	—
Other	**3**	6
	3,354	2,271
Less amount included in current assets	**(128)**	(197)
	$ 3,226	$ 2,074
Liabilities		
Asset removal costs	**$ 576**	$ 567
Accrued pension	**72**	23
Safety and training cost refund	**3**	—
Accrued PSCR/GCR refund	**81**	129
Refundable income taxes	**114**	125
Fermi 2 refueling outage	**16**	25
Other	**2**	2
	864	871
Less amount included in current liabilities	**(99)**	(156)
	$ 765	$ 715

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 pension and postretirement costs* — The traditional rate setting process allows for the recovery of pension and postretirement costs as measured by generally accepted accounting principles. In 2006, we adopted SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans.* See Note 16.
- *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 occurred when fixed cost related revenues did 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. Of the total amount deferred, $11 million represents 2005 expenses and is expected to be recovered during 2007. The remainder relates to 2006 expense, the recovery period of which will be determined upon receipt of an MPSC order.
- *Cost to achieve Performance Excellence Process (PEP)* – The MPSC authorized the deferral of costs to implement the PEP. These costs consist of employee severance, project management and consultant support. These costs will be amortized over a ten-year period beginning with the year subsequent to the year the costs were deferred. See Note 5.
- *Enterprise Business Systems (EBS) Costs* – Starting in 2006, the MPSC approved the deferral of up to $60 million of certain EBS costs that would otherwise be expensed.

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.
- *Safety and training cost refund* – The MPSC ordered the refund of unspent costs which were included in the Company's rate structure.
- *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.
- *Accrued GCR Refund* - Liability for the temporary over-recovery of and a return on gas costs incurred by MichCon which are recoverable through the GCR mechanism.

- *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.
- *Fermi 2 refueling outage* – Liability for refueling outage at Fermi 2 pursuant to MPSC authorization. See Note 3.

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 established 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.

MPSC Show-Cause Order

In March 2006, the MPSC issued an order directing Detroit Edison to show cause by June 1, 2006 why its retail electric rates should not be reduced in 2007. The MPSC cited certain changes that had occurred since the November 2004 order in Detroit Edison's last general rate case, or were expected to occur. These changes included: declines in electric Customer Choice program participation, expiration of the residential rate caps, and projected reductions in Detroit Edison operating costs. The show cause filing was to reflect sales, costs and financial conditions that were expected to occur by 2007. On June 1, 2006, Detroit Edison filed its response explaining why its electric rates should not be reduced in 2007. Detroit Edison indicated that it will have a revenue deficiency of approximately $45 million beginning in 2007 due to significant capital investments over the next several years for infrastructure improvements to enhance electric service reliability and for mandated environmental expenditures. The impacts of these investments will be partially offset by efficiency and cost-savings measures that have been initiated. Therefore, Detroit Edison requested that the show cause proceeding allow for rate increase adjustments based on the combined effects of investment expenditures and cost-savings programs. The MPSC denied this request and indicated that a full review of rates will be made in Detroit Edison's next general rate case, which is due to be filed by July 1, 2007.

The MPSC issued an order approving a settlement agreement in this proceeding on August 31, 2006. The order provided for an annualized rate reduction of $53 million for 2006, effective September 5, 2006. Beginning January 1, 2007, and continuing until the later of March 31, 2008 or 12 months from the filing date of Detroit Edison's next general rate case, rates will be reduced by an additional $26 million, for a total reduction of $79 million. The revenue reduction is net of the recovery of the amortization of the costs associated with the implementation of the Performance Excellence Process. The settlement agreement provides for some level of realignment of the existing rate structure by allocating a larger percentage share of the rate reduction to the commercial and industrial customer classes than to the residential customer classes.

As part of the settlement agreement, a Choice Incentive Mechanism (CIM) was established with a base level of electric choice sales set at 3,400 GWh. The CIM prescribes regulatory treatment of changes in non-fuel revenue attributed to increases or decreases in electric Customer Choice sales. The CIM has a deadband of ±200 GWh. If electric Customer Choice sales exceed 3,600 GWh, Detroit Edison will be able to recover 90% of its reduction in non-fuel revenue from full service customers up to $71 million. If electric Customer Choice sales fall below 3,200 GWh, Detroit Edison will credit 100% of the increase in non-fuel revenue to the unrecovered regulatory asset recovery balances.

Regulatory Accounting Treatment for Performance Excellence Process

In May 2006, Detroit Edison and MichCon filed applications with the MPSC to allow deferral of costs associated with the implementation of the Performance Excellence Process, a company-wide cost-savings and performance improvement program. Implementation costs include project management, consultant support and employee severance expenses. Detroit Edison and MichCon sought MPSC authorization to defer and amortize Performance Excellence Process implementation costs for accounting purposes to match the expected savings from the Performance Excellence Process program with the related CTA. Detroit Edison and MichCon anticipate that the Performance Excellence Process will be carried out over a two to three year period beginning in 2006. Detroit Edison’s CTA is estimated to total between $160 million and $190 million. MichCon’s CTA is estimated to total between $55 million and $60 million. In September 2006, the MPSC issued an order approving a settlement agreement that allows Detroit Edison and MichCon, commencing in 2006, to defer the incremental CTA. Further, the order provides for Detroit Edison and MichCon to amortize the CTA deferrals over a ten-year period beginning with the year subsequent to the year the CTA was deferred. Detroit Edison recorded the deferred CTA costs of $102 million as a regulatory asset and will begin amortizing deferred 2006 costs in 2007 as the recovery of these costs was provided for by the MPSC in the order approving the settlement in the show cause proceeding. MichCon cannot defer CTA costs at this time because a recovery mechanism has not been established.

Electric Industry Restructuring

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.

2004 PSCR Reconciliation and 2004 Net Stranded Cost Case

In accordance with the MPSC's directive 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. In September 2006, the MPSC issued an order recognizing $19 million of 2004 net stranded costs that required Detroit Edison to write off $112 million of 2004 net stranded costs. The MPSC order resulted in a $39 million reduction in the 2004 PSCR over-collection by allowing Detroit Edison to retain the benefit of third party wholesale sales required to support the electric Customer Choice program and to offset the recognition of the $19 million of 2004 stranded costs. The MPSC order also resulted in reductions to accrued interest on the 2004 and 2005 PSCR amounts of $15 million. The MPSC directed Detroit Edison to include the remaining 2004 PSCR over-collection amount and related interest in the 2005 PSCR Reconciliation which is in an under-collected position. The order resulted in a reduction of pre-tax income of approximately $58 million.

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.

Accounting for Costs Related to Enterprise Business Systems (EBS)

In July 2004, Detroit Edison filed an accounting application with the MPSC requesting authority to capitalize and amortize costs related to EBS, 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 EBS costs that would otherwise be expensed, as a regulatory asset for future rate recovery starting January 1, 2006. At December 31, 2006, approximately $9 million of EBS costs have been deferred as a regulatory asset. In addition, EBS costs recorded as plant assets will be amortized over a 15-year period, pursuant to MPSC authorization.

Power Supply Costs 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 were power supply costs, transmission expenses and nitrogen oxide (NOx) 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. In March 2006, Detroit Edison filed its 2005 PSCR reconciliation. The filing sought approval for recovery of approximately $144 million from its commercial and industrial customers. The filing included a motion for entry of an order to implement immediately a reconciliation surcharge of 4.96 mills per kWh on the bills of its commercial and industrial customers. The under-collected PSCR expense allocated to residential customers could not be recovered due to the PA 141 rate cap for residential customers, which expired January 1, 2006. In addition to the 2005 PSCR Plan Year Reconciliation, the filing included a reconciliation for the Pension Equalization Mechanism (PEM) for the periods from November 24, 2004 through December 31, 2004 and from January 1, 2005 through December 31, 2005. The PEM reconciliation seeks to allocate and refund approximately $12 million to customers based upon their contributions to pension expense during the subject periods. The September 2006 order in the Company's 2004 PSCR Reconciliation and Stranded Cost proceeding directed the Company to roll the entire 2004 PSCR over-collection amount to the Company's 2005 PSCR Reconciliation, thereby reducing the Company's 2005 PSCR Reconciliation under-collection amount for commercial and industrial customers to $64 million. An order is expected in the first half of 2007.

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 fuel and power supply costs, including transmission expenses, Midwest Independent Transmission System Operator (MISO) market participation costs, and NOx 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 a fuel additive. In conjunction with DTE Energy's sale of its transmission assets to ITC Transmission in February 2003, the FERC froze ITC Transmission's rates through December 2004. In approving the sale, FERC authorized ITC Transmission's recovery of the difference between the revenue it would have collected and the actual revenue collected during the rate freeze period. This amount is estimated to be $66 million which is to be included in ITC Transmission's rates over a five-year period beginning June 1, 2006. This increased Detroit Edison's transmission expense in 2006 by approximately $7 million. The MPSC authorized Detroit Edison in 2004 to recover 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. In September 2006, the MPSC issued an order in this case that approved the inclusion of sulfur dioxide emission allowance expense in the PSCR, determined that fuel additive expense should not be included in the PSCR based upon its impact on maintenance expense, found the Company's determination of third party sales revenues to be correct, and allowed the Company to increase its PSCR factor for the balance of the year in an effort to reverse the effects of the previously ordered temporary reduction. The MPSC declined to rule on the Company's requests to include mercury emission allowance expense in the PSCR or its request to include prior PSCR over/(under) recoveries in future year PSCR plans. We have filed a petition for re-hearing. In December 2006, Detroit Edison was granted its request to include its updated projection ($81 million) of its 2006 PSCR undercollection in its 2007 PSCR plan. In addition, Detroit Edison was granted the authority to include all PSCR over/(under) collections in future PSCR plans, thereby reducing the time between refund or recovery of PSCR reconciliation amounts.

2007 Plan Year — In September 2006, Detroit Edison filed its 2007 PSCR plan case seeking approval of a levelized PSCR factor of 6.98 mills per kWh above the amount included in base rates for all PSCR customers. The Company's PSCR plan includes $130 million for the recovery of its projected 2006 PSCR under-collection, bringing the total requested PSCR factor to 9.73 mills/kWh. The Company's application includes a request for an early hearing and temporary order granting such ratemaking authority. The Company's 2007 PSCR Plan includes fuel and power supply costs, including NOx and sulfur dioxide emission allowance costs, transmission costs and MISO costs. The Company filed supplemental testimony and briefs in December 2006 supporting its updated request to include approximately $81 million for the recovery of its projected 2006 PSCR under-collection. The MPSC issued a temporary order in December 2006 approving the Company's request. The Company will begin to collect its 2007 power supply costs, including the 2006 rollover amount, through a PSCR factor of 8.69 mills/kWh on January 1, 2007.

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.

Uncollectible Expense Tracker Mechanism and Report of Safety and Training-Related Expenditures

In March 2006, MichCon filed an application with the MPSC for approval of its uncollectible expense tracking mechanism for 2005. This is the first filing MichCon has made under the uncollectible tracking mechanism, which was approved by the MPSC in April 2005 as part of MichCon's last general rate case. MichCon's 2005 base rates included $37 million for anticipated uncollectible expenses. Actual 2005 uncollectible expenses totaled $60 million. The tracker mechanism allows MichCon to recover ninety percent of uncollectibles that exceeded that $37 million base. Under the formula prescribed by the MPSC, MichCon recorded an underrecovery of approximately $11 million for uncollectible expenses from May 2005 (when the mechanism took effect) through the end of 2005. In December 2006, the MPSC issued an order authorizing MichCon to implement the Uncollectible Expense True-up Mechanism (UETM) monthly surcharge for service rendered on and after January 1, 2007. As part of the March 2006 application with the MPSC, MichCon filed a review of the 2005 annual safety and training - related expenditures. MichCon reported that actual safety and training-related expenditures for the initial period exceeded the pro-rata amounts included in base rates and based on the under-recovered position, recommended no refund at this time. In the December 2006 order, the MPSC also approved MichCon's 2005 safety and training report. As of December 31, 2006, MichCon is in a $3 million over-recovery position for safety and training costs.

Gas Cost Recovery Proceedings

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. In March 2006, MPSC Staff filed testimony recommending an adjustment to the accounting treatment of the injected base gas remaining in the New Haven storage field when it was sold in early 2004 that would result in a $3 million reduction to MichCon's accrued underrecovery. In June 2006, an MPSC Administrative Law Judge (ALJ) issued a Proposal for Decision (PFD) recommending an approximately $43 million under-recovery. MichCon recorded the $3 million reduction to the 2004 underrecovery in the second quarter of 2006. The MPSC issued an order in August 2006 authorizing MichCon to roll a $42 million net underrecovery, including interest, into its 2005 – 2006 GCR reconciliation. This order disallowed $0.3 million related to the sale of storage services and concurrent reduction in gas purchases in February and March of 2005. The MPSC also found that the Staff's proposed accounting for the sale of the New Haven injected base gas was appropriate.

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 October 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. In June 2006, MichCon filed its GCR reconciliation for the 2005-2006 GCR year. The filing supported a total over-recovery, including interest through March 2006, of $13 million. MPSC Staff and other interveners filed testimony regarding the reconciliation in December 2006 in which they recommended disallowances related to MichCon's implementation of its dollar cost averaging fixed price program and its use of fixed basis in contracting purchases. In January 2007, MichCon filed testimony rebutting these recommendations. The 2005-2006 GCR plan case is in the early stages of the regulatory review and approval process and the final resolution is uncertain. Based on available information, MichCon is unable to assess the range of a reasonably possible loss related to the proposed disallowances. An MPSC order is expected in 2007.

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. In July 2006, MichCon and the parties to the case reached a settlement agreement that provides for a maximum GCR factor of $8.95 per Mcf, plus quarterly contingent GCR factors. These contingent factors will 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. The MPSC issued an order approving the settlement in August 2006.

2007-2008 Plan Year / Native Base Gas Sale Consolidated – In August 2006, MichCon filed an application with the MPSC requesting permission to sell native base gas that would become accessible with storage facilities upgrades. MichCon estimated sale of this base gas would be worth $34 million. In December 2006, the administrative law judge in the case approved a motion made by the Residential Ratepayer Consortium to consolidate this case with MichCon's 2007-2008 GCR plan case. In December 2006, MichCon filed its 2007-2008 GCR plan case proposing a maximum GCR factor of $8.49 per Mcf. An MPSC Order in the consolidated cases is expected by the end of 2007.

Minimum Pension Liability

At December 31, 2006, we adopted the provisions of SFAS No. 158, *Employers' Accounting for Defined Benefit and Other Postretirement Plans* to recognize the obligations of its pension and postretirement plans. Based on approval received from the MPSC, Detroit Edison recorded the charge to a miscellaneous deferred debit included in regulatory assets in the Consolidated Statement of Financial Position.

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 7 – 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 6. 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 $29 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 2050. It is estimated that the cost of decommissioning Fermi 2, when its license expires in 2025, will be $1.2 billion in 2006 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 Fermi 2 decommissioning and the disposal of low-level radioactive waste through a revenue surcharge. The decommissioning of Fermi 1 is funded by Detroit Edison. The amounts recovered from customers are deposited in the restricted external trust accounts to fund decommissioning.

(in Millions)	**2006**	2005	2004
Revenue	**$39**	$ 40	$ 38
Net unrealized investment gains	**42**	—	17

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

	As of December 31	
(in Millions)	**2006**	2005
Fermi 2	**$ 694**	$ 601
Fermi 1	**15**	18
Low level radioactive waste	**31**	27
Total	**$ 740**	$ 646

At December 31, 2006, investments in the external nuclear decommissioning trust funds consisted of approximately 50% in publicly traded equity securities, 43% 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.

A portion of funds recovered through the Fermi 2 decommissioning surcharge and deposited in external trust accounts is designated for the removal of non-radioactive assets and the clean-up of the Fermi site. This removal and clean-up is not considered a legal liability. Therefore, it is not included in the asset retirement obligation, but is included in the nuclear decommissioning regulatory liability.

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 is currently expanding the Fermi 2 spent fuel pool capacity to meet our storage requirements through 2009. 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 8 — 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, 2006 was as follows:

	Belle River	Ludington Hydroelectric Pumped Storage
In-service date	1984-1985	1973
Total plant capacity	1,026MW	1,872MW
Ownership interest	*	49%
Investment (in Millions)	$ 1,578	$ 164
Accumulated depreciation (in Millions)	$ 815	$ 97

* 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 9 - INCOME TAXES

We file a consolidated federal income tax return. Total income tax expense varied from the statutory federal income tax rate for the following reasons:

(Dollars in Millions)	**2006**	2005	2004
Income before income taxes and minority interest	**$ 324**	$ 498	$ 428
Less minority interest	**(250)**	(281)	(212)
Income from continuing operations before tax	**$ 574**	$ 779	$ 640
Income tax expense at 35% statutory rate	**$ 201**	$ 272	$ 224
Production tax credits	**(35)**	(55)	(38)
Investment tax credits	**(8)**	(8)	(8)
Depreciation	**(4)**	(4)	(4)
Employee Stock Ownership Plan dividends	**(5)**	(5)	(5)
Medicare part D subsidy	**(6)**	(7)	(5)
Other, net	**(6)**	9	12
Income tax expense (benefit) from continuing operations	**$ 137**	$ 202	$ 176
Effective federal income tax rate	**23.9%**	25.9%	27.5%

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 were as follows:

(in Millions)	2006	2005	2004
Continuing Operations			
Current federal and other income tax expense	$ 109	$ 57	$ 42
Deferred federal income tax expense (benefit)	28	145	134
	137	202	176
Discontinued operations	(2)	(13)	(15)
Cumulative Effect of Accounting Changes	1	(2)	—
Total	$ 136	$ 187	$ 161

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 $438 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 $90 million that expires in 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)	2006	2005
Property, plant and equipment	$ (1,358)	$ (1,325)
Securitized regulatory assets	(670)	(723)
Alternative minimum tax credit carryforward	438	484
Merger basis differences	60	115
Pension and benefits	16	(2)
Other Comprehensive Income	113	146
Net operating loss	31	56
Other	150	110
	$ (1,220)	$ (1,139)
Deferred income tax liabilities	$ (3,054)	$ (2,820)
Deferred income tax assets	1,834	1,681
	$ (1,220)	$ (1,139)
Current deferred income tax assets	$ 245	$ 257
Long-term deferred income tax liabilities	(1,465)	(1,396)
	$ (1,220)	$ (1,139)

The above table excludes deferred tax liabilities associated with unamortized investment tax credits which are shown separately on the Consolidated Statement of Financial Position.

In January 2007, we signed an agreement with the IRS acknowledging our acceptance of the results of the 2002 and 2003 audits of our federal income tax returns. We accrue 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, 2006, the Company had accrued approximately $32 million for such uncertainties. We believe that our accrued tax liabilities are adequate for all years. See Note 3 for information regarding the planned January 1, 2007 adoption of FIN 48.

NOTE 10 – COMMON STOCK AND EARNINGS PER SHARE

Common Stock

In December 2006, we repurchased one million shares of DTE Energy common stock for approximately $48.5 million.

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. As a result of a stock award, a settlement of an award of performance shares, or by exercise of a participant's stock option, we may deliver common stock from the Company's authorized but unissued common stock and/or from outstanding common stock acquired by or on behalf of the Company in the name of the participant. The number of non-vested restricted stock awards is included in the number of common shares outstanding; however, for purposes of computing basic earnings per share, non-vested restricted 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.

A reconciliation of both calculations is presented in the following table:

(in Millions, except per share amounts)	2006	2005	2004
Basic Earnings per Share			
Income from continuing operations	**$ 437**	$ 577	$ 464
Average number of common shares outstanding	**177**	175	173
Income per share of common stock based on weighted average number of shares outstanding	**$ 2.46**	$ 3.30	$ 2.69
Diluted Earnings per Share			
Income from continuing operations	**$ 437**	$ 577	$ 464
Average number of common shares outstanding	**177**	175	173
Incremental shares from stock-based awards	**1**	1	—
Average number of dilutive shares outstanding	**178**	176	173
Income per share of common stock assuming issuance of incremental shares	**$ 2.45**	$ 3.28	$ 2.68

Options to purchase approximately 100,000 shares of common stock in 2006 **,** two million shares of common stock in 2005, and one million shares in 2004 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 11 — LONG-TERM DEBT AND PREFERRED SECURITIES

Long-Term Debt

Our long-term debt outstanding and weighted average interest rates(1) of debt outstanding at December 31 were:

(in Millions)	2006	2005
DTE Energy Debt, Unsecured		
6.6% due 2007 to 2033	**$ 1,669**	$ 1,696
Detroit Edison Taxable Debt, Principally Secured		
5.9% due 2010 to 2037	**2,267**	2,030
Detroit Edison Tax Exempt Revenue Bonds (2)		
5.2% due 2008 to 2036	**1,213**	1,145
MichCon Taxable Debt, Principally Secured		
6.2% due 2007 to 2033	**745**	785
Other Long-Term Debt, Including Non-Recourse Debt	**259**	155
	6,153	5,811
Less amount due within one year	**(235)**	(577)
	$ 5,918	$ 5,234
Securitization Bonds	**$ 1,295**	$ 1,400
Less amount due within one year	**(110)**	(105)
	$ 1,185	$ 1,295
Equity-Linked Securities	**$ —**	$ 175
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, 2006 are shown below the description of each debt issue.

(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 2006, we issued the following long-term debt:

Company	Month Issued	Type	Interest Rate	Maturity	(in Millions) Amount
Detroit Edison	May	Senior Notes (1)	6.625%	June 2036	$ 250
DTE Energy	May	Senior Notes (2)	6.35%	June 2016	300
Detroit Edison	December	Tax-Exempt Revenue Bonds (3)	Variable	December 2036	69
				Total Issuances	**$ 619**

(1) The proceeds from the issuance were used to repay short-term borrowings of Detroit Edison and for general corporate purposes.

(2) The proceeds from the issuance were used to repay a portion of DTE Energy's 6.45% Senior Notes due 2006 and for general corporate purposes.

(3) The proceeds from the issuance to be used to finance the construction, acquisition, improvement and installation of certain solid waste disposal facilities at Detroit Edison's Monroe Power Plant.

In October 2006, we purchased the lessor interest in the 66 Bcf Washington 10 gas storage field. Prior to the purchase, we leased the storage rights and lease obligations which were recorded as operating leases. The acquisition resulted in a cash payment of approximately $13 million and the assumption of approximately $133 million of project related debt that was recorded on our statement of financial position.

Debt Retirements and Redemptions

The following debt was retired, through optional redemption or payment at maturity, during 2006.

Company	Month Retired	Type	Interest Rate	Maturity	(in Millions) Amount
MichCon	May	First Mortgage Bonds	7.15%	May 2006	$ 40
DTE Energy	June	Senior Notes (1)	6.45%	June 2006	500
EES Coke Battery	December	Senior Notes (2)	9.38%	April 2007	18
			Total Retirements		**$ 558**

(1) These Senior Notes were paid at maturity with the proceeds from the issuance of Senior Notes by DTE Energy and short-term borrowings.

(2) In addition to its regular payments in 2006, EES Coke Battery Company Senior Notes were paid in full in December.

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

(in Millions)	2007	2008	2009	2010	2011	2012 and thereafter	Total
Amount to mature	$ 346	$ 462	$ 368	$ 686	$ 922	$ 4,962	**$ 7,746**

Remarketable Securities

At December 31, 2006, $75 million of notes of MichCon were subject to periodic remarketings. We do not expect any remarketings to take place in 2007. 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.

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, 2006, 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	6,747,484
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 12 - 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 five-year revolving credit agreements with an aggregate capacity of $925 million. Simultaneously, we amended the October 2004 $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 us to maintain a debt to total capitalization ratio of no more than .65 to l. Should we have delinquent debt obligations of at least $50 million to any creditor, such delinquency will be considered a default under our credit agreements. At December 31, 2006 and December 31, 2005, respectively, we had approximately $123 million and $284 million of letters of credit outstanding against these facilities.

Effective December 31, 2006, the credit agreements were amended to, among other things, exclude MichCon's short-term debt from the debt/capital ratio in the first, third and fourth quarter reporting periods, exclude the effects of SFAS No. 158 in the compliance calculation, and exclude un-drawn letters of credit and guarantees (except for guaranteed debt of non-consolidated third parties) from the debt calculations under these credit agreements.

MichCon, Detroit Edison and DTE Energy are currently in compliance with these financial covenants.

At December 31, 2006, we had outstanding commercial paper of $1.031 billion and other short-term borrowings of $100 million. At December 31, 2005, we had outstanding commercial paper of $841 million and other short-term borrowings of $103 million.

The weighted average interest rates for short-term borrowings were 5.4% and 4.4% at December 31, 2006 and 2005, respectively.

In December 2005, DTE Energy entered into a new $150 million letter of credit and reimbursement agreement. The reimbursement agreement had 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. In December 2006, the agreement was extended for a one-year term and the amount of the facility was reduced to $40 million, reflective of the letters of credit outstanding versus approximately $80 million of letters of credit outstanding as of December 31, 2005. At the same time, the agreement was amended to exclude MichCon's short-term debt from the debt/capital ratio in the first, third and fourth quarter reporting periods, exclude the effects of SFAS No. 158 in the compliance calculation, and exclude un-drawn letters of credit and guarantees (except for guaranteed debt of non-consolidated third parties) from the debt calculations under these credit agreements.

In conjunction with maintaining certain exchange traded risk management positions, we may be required to post cash collateral with our clearing agent. We entered into a margin loan facility with an affiliate of the clearing agent of up to $103 million as of December 31, 2005 in lieu of posting cash. This arrangement was backed by a letter of credit issued by DTE Energy in the amount of $100 million. The amount outstanding under this facility was $103 million as of December 31, 2005. In October 2006, we changed our clearing agent and entered into a new demand financing agreement for up to $150 million. The amount outstanding under this new agreement was $23 million at December 31, 2006.

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 an outstanding balance of $100 million at December 31, 2006 and no outstanding balance at December 31, 2005.

NOTE 13 - CAPITAL AND OPERATING LEASES

Lessee — We lease various assets under capital and operating leases, including coal cars, office buildings, a warehouse, computers, vehicles and other equipment. The lease arrangements expire at various dates through 2031.

Future minimum lease payments under non-cancelable leases at December 31, 2006 were:

(in Millions)	Capital Leases	Operating Leases
2007	$ 14	53
2008	15	41
2009	15	34
2010	14	27
2011	12	24
Thereafter	50	154
Total minimum lease payments	120	$ 333
Less imputed interest	(30)	
Present value of net minimum lease payments	90	
Less current portion	(8)	
Non-current portion	$ 82	

Rental expense for operating leases was $72 million in 2006, $68 million in 2005, and $66 million in 2004.

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, 2006, were as follows:

(in Millions)	
2007	$ 9
2008	9
2009	9
2010	9
2011	9
Thereafter	80
Total minimum future lease receipts	125
Residual value of leased pipeline	40
Less unearned income	(86)
Net investment in capital lease	79
Less current portion	(1)
	$ 78

NOTE 14 – FINANCIAL AND OTHER DERIVATIVE INSTRUMENTS

We comply with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* , as amended. 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 qualify as a hedge and are 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 Energy Trading segment, we do not hold or issue derivative instruments for trading purposes. The fair value of all derivatives is included in “Assets or liabilities from risk management and trading activities” on 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 electric utility operations at December 31, 2006.

MichCon – MichCon purchases, stores, transmits and distributes natural gas and sells storage and transportation capacity. MichCon has fixed-priced contracts for portions of its expected gas supply requirements through 2010. MichCon may also sell forward storage and transportation capacity contracts. These gas supply, firm transportation and storage contracts are designated and qualify for the normal purchases and sales exemption and are therefore accounted for under the accrual method.

Non-Utility Operations

Power and Industrial Projects – These business segments manage and operate on-site energy and steel related projects, landfill gas recovery and power generation assets. These businesses utilize fixed-priced contracts in their marketing and management of their assets. These contracts are not derivatives and are therefore accounted for under the accrual method.

Synthetic Fuel – 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 2.

To manage our exposure in 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 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 2007 are less than $60 per barrel, then the derivatives will yield no payment. If the price per barrel begins to exceed the base $60 per barrel figure, then the derivatives will begin to yield a payment. These agreements do not qualify for hedge accounting. Consequently, changes in the fair value of the options are recorded currently in earnings. 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” item line on 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. Amounts recorded in other comprehensive loss will be reclassified to earnings, specifically as a component of Operating revenues, as the related production affects earnings through 2013. In 2006 and 2005, $86 million and $35 million, respectively, of after-tax losses were reclassified to earnings. In 2007, we estimate reclassifying an after-tax loss of approximately $28 million to earnings.

Energy Trading – Energy Trading markets and trades wholesale electricity and natural gas physical products, energy 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, specifically as a component of Operating revenues, unless certain hedge accounting criteria are met. This fair value accounting better aligns financial reporting with the way the business is managed and its performance measured. Energy Trading 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 related derivatives result in unrealized gains and losses being recorded to earnings that eventually reverse upon settlement. For derivatives designated as cash flow hedges, amounts recorded in Other Comprehensive Income will be reclassified to earnings, specifically as a component of Operating revenues, as the related forecasted transaction affects earnings through 2008. In 2007, we estimate reclassifying an after-tax loss of approximately $7 million to earnings.

Coal and Gas Midstream – These business units are primarily engaged in services related to marketing and transportation of coal as well as the transportation, processing and storage of natural gas. These businesses utilize fixed-priced contracts in their marketing and management of their businesses. These contracts are not derivatives and are therefore accounted for under the accrual method.

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 2007, 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 impacts 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.

	2006		2005	
	Fair Value	**Carrying Value**	Fair Value	Carrying Value
Long-Term Debt	**$8.0 billion**	**$7.7 billion**	$7.9 billion	$7.7 billion

NOTE 15 - COMMITMENTS AND CONTINGENCIES

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 $875 million through 2006. We estimate Detroit Edison future capital expenditures at up to $222 million in 2007 and up to $2 billion of additional capital expenditures through 2018 to satisfy both the existing and proposed new control requirements.

Water – In response to an EPA regulation, 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. Initially, it was estimated that the Company could incur up to approximately $53 million over the next three to five years in additional capital expenditures to comply with these requirements. However, a recent court decision remanded back to the EPA several provisions of the federal regulation resulting in a delay in complying with the regulation. The decision also raised the possibility that the Company may have to install cooling towers at some facilities at a cost substantially greater than was initially estimated for other mitigative technologies.

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 $11 million which was accrued in 2006 and is expected to be incurred over the next several years. In addition, Detroit Edison expects to make approximately $5 million of capital improvements to the ash landfill in 2007.

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. As a result of a study completed in 1995, Gas Utility accrued an additional liability and a corresponding regulatory asset of $35 million. During 2006, we spent approximately $2 million investigating and remediating these former MGP sites. In December 2006, we retained multiple environmental consultants to estimate the projected cost to remediate each MGP site. We accrued an additional $7 million in remediation liabilities associated with former MGP holders and additional cleanup cost, to increase the reserve balance to $41 million as of December 31, 2006, with a corresponding increase in the regulatory asset.

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 one year at a cost of approximately $14 million. Our other non-utility affiliates are substantially in compliance with all environmental requirements.

Guarantees

In certain limited 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 $22 million at December 31, 2006.

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 $383 million at December 31, 2006. 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 took legal action attempting to prevent the STC from implementing the new valuation tables and continued to prepare assessments based on the superseded tables.

In December 2005, a settlement agreement was reached and executed Stipulations for Consent Judgment, Consent Judgments, and Schedules to Consent Judgment were filed with the Michigan Tax Tribunal 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 settlement agreement and resolves a number of claims by the litigants against each other including both property and non-property issues. The settlement agreement resulted in a pre-tax economic benefit to DTE Energy of $43 million in 2005 that included the release of a litigation reserve.

Labor Contracts

There are several bargaining units for our represented employees. Approximately 3,245 of our represented employees are under contracts that expire in June 2007 and 970 employees are under contracts that expire in October 2007. The contracts of the remaining represented employees expire at various dates in 2008 and 2009.

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 approximately $42 million of steam and electricity in 2006, 2005 and 2004. We estimate steam and electric purchase commitments through 2024 will not exceed $386 million. 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 $63 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, 2006, 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 $6.5 billion through 2051. We also estimate that 2007 capital expenditures will be $1.5 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

Detroit Edison and DTE Coal Services Inc. are involved in a contract dispute with BNSF Railway Company that has been referred to arbitration. Under this contract, BNSF transports western coals east for Detroit Edison and DTE Coal Services. We have filed a breach of contract claim against BNSF for the failure to provide certain services that we believe are required by the contract. The arbitration hearing is scheduled for mid-2007. While we believe we will prevail on the merits in this matter, a negative decision with respect to the significant issues being heard in the arbitration could have an adverse effect on our ability to grow the Coal and Gas Midstream business segment as currently contemplated.

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 6 and 7 for a discussion of contingencies related to Regulatory Matters and Nuclear Operations.

NOTE 16 - RETIREMENT BENEFITS AND TRUSTEED ASSETS

Adoption of SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*

In September 2006, the FASB issued SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans — an Amendment of FASB Statements No. 87, 88, 106, and 132(R)*. SFAS 158 requires companies to (1) recognize the overfunded or underfunded status of defined benefit pension and defined benefit other postretirement plans in its financial statements, (2) recognize as a component of other comprehensive income, net of tax, the actuarial gains or losses and the prior service costs or credits that arise during the period but are not immediately recognized as components of net periodic benefit cost, (3) recognize adjustments to other comprehensive income when the actuarial gains or losses, prior service costs or credits, and transition assets or obligations are recognized as components of net periodic benefit cost, (4) measure postretirement benefit plan assets and plan obligations as of the date of the employer's statement of financial position, and (5) disclose additional information in the notes to financial statements about certain effects on net periodic benefit cost in the upcoming fiscal year that arise from delayed recognition of the actuarial gains and losses and the prior service cost and credits.

The requirement to recognize the funded status of a postretirement benefit plan and the related disclosure requirements is effective for fiscal years ending after December 15, 2006. We adopted this requirement as of December 31, 2006. The requirement to measure plan assets and benefit obligations as of the date of the employer's fiscal year-end statement of financial position is effective for fiscal years ending after December 15, 2008. We plan to adopt this requirement as of December 31, 2008.

Detroit Edison received approval from the MPSC to record the charge related to the additional liability as a miscellaneous deferred debit in the regulatory asset line on the Consolidated Statement of Financial Position since the traditional rate setting process allows for the recovery of pension and other postretirement plan costs. Retrospective application of the changes required by SFAS No. 158 is prohibited; therefore certain disclosures below are not comparable.

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, 2006 and December 31, 2005 are based on measurement dates of November 30, 2006 and November 30, 2005, respectively. Amounts reported in tables for the year ended December 31, 2006 are based on a measurement date of November 30, 2005. 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.

Qualified and Nonqualified Pension Plan Benefits

We have qualified defined benefit retirement plans for eligible represented and nonrepresented employees. The plans are noncontributory and cover substantially all employees. The plans provide traditional retirement benefits based on the employees' years of benefit service, average final compensation and age at retirement. In addition, certain represented and nonrepresented employees are covered under cash balance provisions that base benefits on annual employer contributions and interest credits. 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.

Our policy is to fund qualified pension costs by contributing amounts consistent with the Pension Protection Act of 2006 provisions and additional amounts when we deem appropriate. In December 2006, we contributed $180 million to the qualified pension plans and $15 million to the nonqualified pension plans. We anticipate making up to a $180 million contribution to our qualified pension plans in 2007 and a $15 million contribution to our nonqualified pension plans in 2007.

Net pension cost includes the following components:

	Qualified Pension Plans			Nonqualified Pension Plans		
(in Millions)	**2006**	2005	2004	**2006**	2005	2004
Service Cost	**$ 62**	$ 64	$ 58	**$ 2**	$ 2	$ 2
Interest Cost	**172**	169	168	**4**	3	3
Expected Return on Plan Assets	**(222)**	(218)	(216)	**—**	—	—
Amortization of						
Net actuarial loss	**57**	67	63	**2**	1	1
Prior service cost	**7**	8	8	**1**	—	—
Special Termination Benefits	**49**	—	—	**—**	—	—
Net Pension Cost	**$ 125**	$ 90	$ 81	**$ 9**	$ 6	$ 6

Amounts in accumulated other comprehensive loss and regulatory assets expected to be recognized as components of net periodic benefit cost during 2007 are comprised of $56 million of net actuarial loss and $5 million of prior service cost relating to qualified pension plans and $2 million of net actuarial loss and $1 million of prior service cost relating to nonqualified pension plans. We recorded a $49 million pension cost associated with our Performance Excellence Process in 2006.

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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:

	Qualified Pension Plans		Nonqualified Pension Plans	
(in Millions)	2006	2005	2006	2005
Accumulated Benefit Obligation-End of Period	$ 2,934	$ 2,741	$ 73	$ 61
Projected Benefit Obligation-Beginning of Period	$ 3,013	$ 2,899	$ 67	$ 56
Service Cost	62	64	2	2
Interest Cost	172	169	4	3
Actuarial Loss	78	49	7	10
Benefits Paid	(197)	(168)	(5)	(4)
Special Termination Benefits	49	—	—	—
Plan Amendments	(6)	—	—	—
Projected Benefit Obligation-End of Period	$ 3,171	$ 3,013	$ 75	$ 67
Plan Assets at Fair Value-Beginning of Period	$ 2,617	$ 2,565	$ —	$ —
Actual Return on Plan Assets	324	220	—	—
Company Contributions	—	—	5	4
Benefits Paid	(197)	(168)	(5)	(4)
Plan Assets at Fair Value-End of Period	$ 2,744	$ 2,617	$ —	$ —
Funded Status of the Plans	$ (427)	$ (396)	$ (75)	$ (67)
December Contribution	180	—	—	1
Funded Status, End of Year	$ (247)	$ (396)	$ (75)	$ (66)
Unrecognized (a)				
Net Actuarial loss (a)		1,023		23
Prior service cost (a)		27		2
Net Amount Recognized-End of Period (a)		$ 654		$ (41)
Amount Recorded as (a)				
Prepaid pension assets (a)		186		—
Accrued pension liability (a)		(224)		(60)
Regulatory asset (a)		532		12
Accumulated other comprehensive loss (a)		129		5
Intangible Asset (a)		31		2
		$ 654		$ (41)
Noncurrent Assets (b)	$ 71		$ —	
Current Liabilities (b)	—		$ (5)	
Noncurrent Liabilities (b)	$ (318)		$ (70)	
	$ (247)		(75)	
Amounts Recognized in				
Accumulated other comprehensive loss (b)				
Net Actuarial loss (b)	$ 186		$ 7	
Prior service (credit) (b)	(10)		—	
Regulatory Assets (b)				
Net Actuarial loss (b)	756		21	
Prior service cost (b)	24		1	

(a) - Disclosure no longer required by FAS 158, adopted in 2006, retroactive adoption not permitted.

(b) - New disclosure required by FAS 158, adopted in 2006, retroactive adoption not permitted.

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

	2006	2005	2004
Projected Benefit Obligation			
Discount rate	**5.70%**	5.90%	6.00%
Annual increase in future compensation levels	**4.0%**	4.0%	4.0%
Net Pension Costs			
Discount rate	**5.90%**	6.00%	6.25%
Annual increase in future compensation levels	**4.0%**	4.0%	4.0%
Expected long-term rate of return on Plan assets	**8.75%**	9.0%	9.0%

At December 31, 2006, 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)	
2007	**$ 179**
2008	**183**
2009	**190**
2010	**199**
2011	**204**
2012 - 2016	**1,157**
Total	**$ 2,112**

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 on 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 utilized in a risk controlled manner, to potentially increase the portfolio beyond the market value of invested assets and reduce portfolio investment risk. 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:

	2006	2005
Equity Securities	**68%**	68%
Debt Securities	**23**	27
Other	**9**	5
	100%	100%

Our plans' weighted-average asset target allocations by asset category at December 31, 2006 were as follows:

Equity Securities	**65%**
Debt Securities	**20**
Other	**15**
	100%

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 2006, $29 million in 2005, and $28 million in 2004.

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. In 2006, we made cash contributions of $116 million to our postretirement benefit plans. At the discretion of management, we may make up to a $116 million contribution to our VEBA trusts in 2007.

Net postretirement cost includes the following components:

(in Millions)	2006	2005	2004
Service Cost	**$ 59**	$ 55	$ 41
Interest Cost	**115**	105	92
Expected Return on Plan Assets	**(61)**	(70)	(56)
Amortization of Net loss	**72**	60	43
Prior service (credit)	**(3)**	(2)	(3)
Net transition obligation	**7**	7	8
Special Termination Benefits	**8**	—	—
Net Postretirement Cost	**$ 197**	$ 155	$ 125

Amounts in accumulated other comprehensive loss or regulatory assets expected to be recognized as components of net periodic benefit cost during 2007 are comprised of $66 million of net actuarial loss, $2 million gain of prior service cost and $7 million of net transition obligation. We recorded an $8 million postretirement benefit cost associated with our Performance Excellence Process in 2006.

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)	2006	2005
Accumulated Postretirement Benefit Obligation-Beginning of Period	**$ 1,991**	$ 1,793
Service Cost	**59**	55
Interest Cost	**115**	105
Actuarial Loss	**101**	136
Plan Amendments	**2**	(10)
Medicare Part D Subsidy	**1**	—
Special Termination Benefits	**8**	—
Benefits Paid	**(93)**	(88)
Accumulated Postretirement Benefit Obligation-End of Period	**$ 2,184**	$ 1,991
Plan Assets at Fair Value-Beginning of Period	**$ 713**	$ 679
Actual Return on Plan Assets	**86**	61
Company Contributions	**60**	40
Benefits Paid	**(65)**	(67)
Plan Assets at Fair Value-End of Period	**$ 794**	$ 713
Funded Status of the Plans	**$ (1,390)**	$ (1,278)
December Adjustment	**(24)**	(58)
Funded Status, as of December 31	**$ (1,414)**	$ (1,336)
Unrecognized (a)		
Net Actuarial loss (a)		896
Prior service (credit) (a)		(12)
Net transition obligation (a)		46
Liability-End of Period (a)		$ (406)
Noncurrent Assets (b)	**$ —**	
Current Liabilities (b)	**$ —**	
Noncurrent Liabilities (b)	**$ (1,414)**	
Amounts Recognized in		
Accumulated other comprehensive loss (b)		
Net Actuarial loss (b)	**$ 85**	
Prior service (credit) (b)	**$ (44)**	
Net transition obligation (b)	**$ (35)**	
Regulatory Assets (b)		
Net Actuarial loss (b)	**816**	
Prior service cost (b)	**36**	
Net transition obligation (b)	**74**	

(a) - Disclosure no longer required by FAS 158, adopted in 2006, retroactive adoption not permitted.

(b) - New disclosure required by FAS 158, adopted in 2006, retroactive adoption not permitted.

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

	2006	2005	2004
Projected Benefit Obligation			
Discount rate	**5.70%**	5.90%	6.00%
Net Benefit Costs			
Discount rate	**5.90%**	6.00%	6.25%
Expected long-term rate of return on Plan assets	**8.75%**	9.00%	9.00%

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 $30 million and increased the accumulated benefit obligation by $272 million at December 31, 2006. 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 $25 million and would have decreased the accumulated benefit obligation by $230 million at December 31, 2006.

At December 31, 2006, 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)	
2007	$ **122**
2008	**127**
2009	**131**
2010	**135**
2011	**139**
2012 - 2016	**726**
Total	**$ 1,380**

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 3, 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 $17 million in 2006, $20 million in 2005 and $16 million in 2004.

At December 31, 2006, 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)	
2007	$ 5
2008	5
2009	5
2010	7
2011	7
2012 - 2016	35
Total	$ 64

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:

	2006	2005
Equity Securities	68%	68%
Debt Securities	25	28
Other	7	4
	100%	100%

Our plans' weighted-average asset target allocations by asset category at December 31, 2006 were as follows:

Equity Securities	65%
Debt Securities	20
Other	15
	100%

The adoption of SFAS No. 158 had the following incremental effect on the financial statement line items shown below:

(in Millions)	Qualified Plans	Non-Qualified Plans	Postretirement Plans	Total Benefit Plans
Increase (Decrease) in Assets and Liabilities				
Prepaid pension assets	$ (180)	$ —	$ —	$ (180)
Accrued pension liability	$ 133	$ 3	$ —	$ 136
Accrued postretirement liability	—	—	933	933
Intangible assets	$ (17)	$ (1)	$ —	$ (18)
Deferred income taxes asset	$ 19	$ —	$ 2	$ 21
Regulatory assets	$ 277	$ 4	$ 927	$ 1,208
Accumulated other comprehensive loss	$ 34	$ —	$ 4	$ 38

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 17 – 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. Participants in the plan include our employees and members of our Board of Directors. In the second quarter of 2006, we adopted a new Long-Term Incentive Program (LTIP).

The following are the key points of the newly adopted LTIP:

- Authorized limit is 9,000,000 shares of common stock;
- Prohibits the grant of a stock option with an exercise price that is less than the fair market value of the Company's stock on the date of the grant; and
- Imposes the following award limits to a single participant in a single calendar year, (1) options for more than 500,000 shares of common stock; (2) stock awards for more than 150,000 shares of common stock; (3) performance share awards for more than 300,000 shares of common stock (based on the maximum payout under the award); or (4) more than 1,000,000 performance units, which have a face amount of $1.00 each.

As of December 31, 2006, no performance units have been granted under either the LTIP or the previous stock incentive plan.

Effective January 1, 2006, we adopted SFAS No. 123(R), *Share-Based Payment,* using the modified prospective transition method. Under this method, we record compensation expense at fair value over the vesting period for all awards we grant after the date we adopted the standard. In addition, we are required to record compensation expense at fair value (as previous awards continue to vest) for the unvested portion of previously granted stock option awards that were outstanding as of the date of adoption. Pre-adoption awards of stock awards and performance shares will continue to be expensed. DTE did not make the one-time election to adopt the alternative transition method described in FSP SFAS 123(R)-3, *Transition Election Related to Accounting for the Tax Effect of Share-Based Payment Awards,* but has chosen instead to follow the original guidance provided by SFAS 123(R) in accounting for the tax effects of stock based compensation awards.

The adoption of SFAS 123(R) in 2006 resulted in the following:

- Income from continuing operations was reduced by $2 million;
- Net income was reduced by $1 million;
- Operating and financing cash flows were not materially impacted; and
- Had no material effect on basic or diluted earnings per share.

Stock-based compensation for the reporting periods is as follows:

	2006	2005	2004
Stock-based compensation expense	**$ 24**	$ 13	$ 12
Tax benefit of compensation expense	**$ 8**	$ 5	$ 4

The cumulative effect of the adoption of SFAS 123(R) was an increase in net income of $1 million as a result of estimating forfeitures for previously granted stock awards and performance shares. We have not restated any prior periods as a result of the adoption of SFAS 123(R). We generally purchase shares on the open market for options that are exercised or we may settle in cash other stock based compensation.

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	(in Millions) Aggregate Intrinsic Value
Options outstanding at January 1, 2006	6,236,343	$ 41.31	
Granted	621,720	$ 43.39	
Exercised	(1,009,126)	$ 40.63	
Forfeited or Expired	(181,740)	$ 43.20	
Options outstanding at December 31, 2006	5,667,197	$ 41.60	$ 26
Options exercisable at December 31, 2006	4,104,375	$ 41.09	$ 21

(1) The weighted average remaining contractual life for the exercisable shares is 5.25 years.

(2) As of December 31, 2006 1,562,822 options were nonvested.

(3) During 2006 1,169,744 options vested in this period.

The weighted average grant date fair value of options granted during 2006, 2005 and 2004 was $6.12, $5.89, $4.46, respectively. The intrinsic value of options exercised for both the year ended December 31, 2006, 2005 and 2004 was $6 million, $8 million, and $7 million, respectively. Total option expense recognized during 2006 was $6 million.

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 (years)
$27.62 - $38.04	337,395	$ 31.09	2.90
$38.60 - $42.44	2,961,657	$ 40.63	5.79
$42.60 - $44.50	948,390	$ 43.13	7.39
$44.56 - $48.00	1,419,755	$ 45.08	6.59
	5,667,197	$ 41.60	6.09

We determine the fair value for these options at the date of grant using a Black-Scholes based option pricing model and the following assumptions:

	December 31 2006	December 31 2005	December 31 2004
Risk-free interest rate	**4.58%**	3.93%	3.55%
Dividend yield	**4.75%**	4.60%	5.23%
Expected volatility	**19.79%**	19.56%	20.00%
Expected life	**6** years	6 years	6 years

In connection with the adoption of SFAS 123(R) we reviewed and updated our forfeiture, expected term and volatility assumptions. We modified option volatility to include both historical and implied share-price volatility. Implied volatility is derived from exchange traded options on DTE Energy common stock. Volatility for 2006 was estimated based solely upon historical share-price volatility. Our expected term is based on industry standards.

Pro forma information for the periods ended December 31, 2005 and 2004 is provided to show what our net income and earnings per share would have been if compensation costs had been determined as prescribed by SFAS 123(R):

(in Millions, except per share amounts)	December 31, 2005		December 31, 2004	
Net Income As Reported	$	537	$	431
Less: Total stock-based expense		(4)		(6)
Pro Forma Net Income	$	533	$	425
Earnings per share				
Basic – as reported	$	3.07	$	2.50
Basic – pro forma	$	3.05	$	2.46
Diluted – as reported	$	3.05	$	2.49
Diluted – pro forma	$	3.03	$	2.45

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 periods ended December 31 was:

	2006	2005	2004
Fair value of awards vested (in Millions)	**$ 5**	$ 4	**$** 6
Restricted common shares awarded	**282,555**	288,360	209,650
Weighted average market price of shares awarded	**$ 43.64**	**$** 44.95	**$** 39.95
Compensation cost charged against income (in Millions)	**$ 10**	$ 8	**$** 6

The following table summarizes our stock awards activity for the period ended December 31, 2006:

	Restricted Stock	Weighted Average Grant Date Fair Value
Balance at December 31, 2005	544,087	$42.68
Grants	282,555	$43.64
Forfeitures	(45,561)	$43.03
Vested	(114,945)	$41.86
Balance at December 31, 2006	666,136	$43.20

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 and market conditions. 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.

We recorded compensation expense as follows:

(in Millions)	**2006**	2005	2004
Compensation expense	**$ 8**	$5	$6
Cash settlements (1)	**$ 4**	$5	$6

(1) approximates the intrinsic value of the liability.

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, 2006, there were 1,035,696 performance share awards outstanding.

The following table summarizes our performance share activity for the period ended December 31, 2006:

	Performance Shares
Balance at December 31, 2005	803,071
Grants	520,395
Forfeitures	(132,545)
Payouts	(155,225)
Balance at December 31, 2006	1,035,696

Unrecognized Compensation Costs

As of December 31, 2006, there was $26 million of total unrecognized compensation cost related to non-vested stock incentive plan arrangements. That cost is expected to be recognized over a weighted-average period of 1.35 years.

Type	(In Millions) Unrecognized Compensation cost	(in years) Weighted Average to be recognized
Stock Awards	$ 11	1.19
Performance Shares	11	1.56
Options	4	1.26
	$ 26	1.35

The tax benefit realized for tax deductions related to our stock incentive plan totaled $8 million for the period ended December 31, 2006. Approximately $1.6 million of compensation cost was capitalized as a part of fixed assets during 2006.

NOTE 18 - SEGMENT AND RELATED INFORMATION

In the third quarter of 2006, we realigned the non-utility segment Power and Industrial Projects business unit to separately present the Synthetic Fuel business. The impending expiration of synfuel tax credits as of December 31, 2007, combined with the sustained volatility of oil prices, increased management focus on synfuels, thereby requiring a separate business segment. In the fourth quarter of 2006, we separated the Fuel Transportation and Marketing segment into Coal and Gas Midstream, and Energy Trading corresponding to additional management focus on the results of these non-utility segments. Based on the following 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 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

- *Coal and Gas Midstream*, primarily consisting of coal transportation and marketing, and gas pipelines, processing and storage;
- *Unconventional Gas Production,* primarily consisting of unconventional gas project development and production;
- *Power and Industrial Projects*, primarily consisting of on-site energy services, steel-related projects and power generation with services;
- *Energy Trading,* primarily consisting of energy marketing and trading operations; and
- *Synthetic Fuel,* consisting of the operations of nine synfuel plants.

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

Prior year segment information has been reclassified to conform to the current year's segment structure.

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 federal 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)	2006	2005	2004
Electric Utility	**$ 59**	$ 207	$ 218
Coal and Gas Midstream	**180**	152	180
Unconventional Gas Production	**134**	154	121
Energy Trading	**75**	116	73
	$ 448	$ 629	$ 592

Financial data of the business segments follows:

(in Millions)	Operating Revenue	Depreciation, Depletion & Amortization	Interest Income	Interest Expense	Income Taxes	Net Income	Total Assets	Goodwill	Capital Expenditures
2006									
Electric Utility	$ 4,737	$ 809	$ (4)	$ 278	$161	$325	$ 14,540	$1,206	$ 972
Gas Utility	1,849	94	(9)	67	11	50	3,123	773	155
Non-utility Operations:									
Coal and Gas Midstream	707	4	(3)	10	28	50	435	13	53
Unconventional Gas Production.	99	27	—	13	5	9	611	8	186
Power and Industrial Projects	409	48	(8)	29	(56)	(80)	864	36	35
Energy Trading	830	6	(12)	15	49	96	1,220	17	2
Synthetic Fuel	863	24	(21)	1	(9)	48	662	4	—
	2,908	109	(44)	68	17	123	3,792	78	276
Corporate & Other	5	2	(52)	174	(52)	(61)	2,307	—	—
Reconciliation and Eliminations	(477)	—	62	(61)	—	—	—	—	—
Total from Continuing Operations	$9,022	$ 1,014	$ (47)	$526	$ 137	437	23,762	2,057	1,403
Discontinued Operations (Note 4)						(5)	23	—	—
Cumulative Effect of Accounting Change (Notes 3 and 17)						1	—	—	—
Total						$ 433	$23,785	$2,057	$ 1,403

(in Millions)	Operating Revenue	Depreciation, Depletion & Amortization	Interest Income	Interest Expense	Income Taxes	Net Income	Total Assets	Goodwill	Capital Expenditures
2005									
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:									
Coal and Gas Midstream	707	3	(3)	4	22	45	373	12	28
Unconventional Gas Production	74	20	—	8	1	4	434	8	144
Power and Industrial Projects	428	48	(5)	20	(7)	4	1,043	37	29
Energy Trading	977	4	(3)	17	(23)	(43)	1,834	17	8
Synthetic Fuel	927	58	(36)	1	96	305	1,049	4	2
	3,113	133	(47)	50	89	315	4,733	78	211
Corporate & Other	10	—	(40)	187	(34)	(52)	2,358	—	4
Reconciliation and Eliminations	(702)	—	43	(43)	—	—	—	—	—
Total from Continuing Operations	$9,021	$ 868	$(57)	$519	$202	577	23,304	2,057	1,065
Discontinued Operations (Note 4)						(37)	31	—	—
Cumulative Effect of Accounting Change (Note 1)						(3)	—	—	—
Total						$537	$23,335	$2,057	$ 1,065

(in Millions)	Operating Revenue	Depreciation, Depletion & Amortization	Interest Income	Interest Expense	Income Taxes	Net Income	Total Assets	Goodwill	Capital Expenditures
2004									
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:									
Coal and Gas Midstream	589	3	(3)	3	19	33	328	11	16
Unconventional Gas Production	71	18	—	10	3	6	301	8	38
Power and Industrial Projects	448	53	(1)	35	(19)	(17)	940	37	24
Energy Trading	665	3	(1)	5	45	85	952	17	8
Synthetic Fuel	650	33	(42)	—	63	199	875	4	—
	2,423	110	(47)	53	111	306	3,396	77	86
Corporate & Other	17	3	(48)	174	10	(12)	2,284	—	2
Reconciliation and Eliminations.	(621)	—	49	(49)	—	—	—	—	—
Total from Continuing Operations	$7,069	$ 739	$(55)	$516	$176	464	21,204	2,051	903
Discontinued Operations (Note 4)						(33)	93	16	1
Total						$ 431	$21,297	$2,067	$ 904

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NOTE 19 — 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. Georgetown was reported as a discontinued operation beginning in the fourth quarter 2006, resulting in the adjustment of prior quarterly results. See Note 4.

(in Millions, except per share amounts)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
2006					
Operating Revenues	**$ 2,635**	**$ 1,895**	**$ 2,196**	**$ 2,296**	**$ 9,022**
Operating Income (Loss)	**$ 242**	**$ (30)**	**$ 373**	**$ 243**	**$ 828**
Net Income (Loss)					
From continuing operations	**$ 136**	**$ (32)**	**$ 189**	**$ 144**	**$ 437**
Discontinued operations	**(1)**	**(1)**	**(1)**	**(2)**	**(5)**
Cumulative effect of accounting change	**1**	**—**	**—**	**—**	**1**
Total	**$ 136**	**$ (33)**	**$ 188**	**$ 142**	**$ 433**
Basic Earnings (Loss) per Share					
From continuing operations	**$ .76**	**$ (.18)**	**$ 1.07**	**$ .81**	**$ 2.46**
Discontinued operations	**—**	**(.01)**	**(.01)**	**(.01)**	**(.03)**
Cumulative effect of accounting change	**.01**	**—**	**—**	**—**	**.01**
Total	**$ .77**	**$ (.19)**	**$ 1.06**	**$ .80**	**$ 2.44**
Diluted Earnings (Loss) per Share					
From continuing operations	**$ .76**	**$ (.18)**	**$ 1.07**	**$ .81**	**$ 2.45**
Discontinued operations	**—**	**(.01)**	**(.01)**	**(.01)**	**(.03)**
Cumulative effect of accounting change	**—**	**—**	**—**	**—**	**.01**
Total	**$ .76**	**$ (.19)**	**$ 1.06**	**$ .80**	**$ 2.43**
2005					
Operating Revenues	$ 2,309	$ 1,941	$ 2,059	$ 2,712	$ 9,021
Operating Income	$ 224	$ 90	$ 52	$ 581	$ 947
Net Income (Loss)					
From continuing operations	$ 126	$ 33	$ 30	$ 388	$ 577
Discontinued operations	(4)	(4)	(26)	(3)	(37)
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	$ 3.30
Discontinued operations	(.02)	(.02)	(.15)	(.01)	(.21)
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	$ 3.28
Discontinued operations	(.02)	(.02)	(.15)	(.02)	(.21)
Cumulative effect of accounting change	—	—	—	(.02)	(.02)
Total	$ .70	$ .17	$ .02	$ 2.14	$ 3.05

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

Executive Deferred Compensation Plan

On October 30, 2006, the DTE Energy Company Executive Deferred Compensation Plan was amended so that no eligible employee under the plan may elect to defer any Performance Shares or Annual Cash Bonus payable after December 31, 2006, as those terms are defined in the plan.

Annual Incentive Plan

On February 23, 2007 the Organization and Compensation Committee of DTE Energy Company ("Company") Board of Directors approved 2007 performance measures and targets for Anthony F. Earley Jr., Gerard Anderson and David Meador under the Company's Annual Incentive Plan ("AIP"). These named executive officers and other executives may receive cash awards under the AIP. For 2007, the AIP has ten annual measures for Mr. Earley, Mr. Anderson and Mr. Meador weighted as follows in determining the total annual incentive award: enterprise earnings per share (20%), enterprise cash flow (20%), amount of monetization proceeds (10%), monetization timing (10%), utility customer satisfaction (10%), MPSC complaint reduction improvement (5%) minority diversity (3.75%), women diversity (3.75%), safety (7.5%) and Institute of Nuclear Power Operations ('INPO') Index (10%).

On February 23, 2007 the Organization and Compensation Committee also approved modifications to Mr. Buckler's 2007 AIP to align the customer satisfaction and MPSC goals with those of the Messrs. Earley, Anderson and Meador. For 2007 Mr. Buckler's AIP has annual measures weighted as follows in determining the total annual incentive award: enterprise earnings per share (7.5%), enterprise cash (7.5%), Detroit Edison earnings per share (15%), Detroit Edison cash (10%), success of the SAP installation project (10%), minority diversity (3.75%), women diversity (3.75%) safety (7.5%), performance excellence process success (15%), utility customer satisfaction (7.5%), MPSC complaint reduction improvement (7.5%), and random outage rate (5.0%).

The Company must attain minimum threshold levels for a given performance measure before any compensation becomes payable on account of the measure. Based on market comparisons, each officer position is assigned a target award expressed as a percentage of base salary. Targets for these officers range from 55% to 100%, including the Chief Executive Officer. Award amounts paid to each officer are determined as follows: (i) performance for each measure is combined for an overall corporate performance factor that ranges from 0% to 175% of target; (ii) this weighted average factor is multiplied by each officer's target award to arrive at an initial calculation; and (iii) the initial calculation is adjusted based on individual performance modifier that may range from 0% to 150%.

Long-Term Incentive Plan

On January 17, 2007 the Organization and Compensation Committee of DTE Energy Company ("Company") Board of Directors approved 2007 performance measures and targets for executive officers under the DTE Energy Company 2007 Long Term Incentive Plan ("LTIP"). The LTIP, which was approved by our shareholders, rewards long-term growth and profitability by providing a vehicle through which officers, other key employees and outside directors may receive stock-based compensation. Stock-based compensation directly links individual performance with shareholder interests. The level of awards is determined by reference to executive level, responsibility, retention issues, market competitiveness and contributions to the overall success of the Company. Mr. Earley, Mr. Anderson, Mr. Meador and Mr. Buckler are eligible for awards equal to 140% of their base salary which are delivered in the form of restricted stock, options and performance shares.

Performance shares: Performance shares entitle the executive to receive a specified number of shares, or a cash payment equal to the fair market value of the shares, or a combination thereof, depending on the level of achievement of performance measures. The performance measurement period for the 2007 award is January 1, 2007 through December 31, 2009. Payments earned under the 2007 award can range from 0% to 200% of target, based upon achievement of three corporate performance measures weighted as follows: (i) balance sheet health (15%), (ii) total shareholder return vs. shareholder return of the companies currently in the Standard & Poor's Utility Index (70%), and (iii) employee engagement (15%).

Part III

Item 10. Directors, Executive Officers and Corporate Governance

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, and Director Independence

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 2007 Annual Meeting of Common Shareholders to be held May 3, 2007. 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.

PartIV

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.

10-66	First Amendment to the DTE Energy Company Deferred Stock Compensation Plan for Non-Employee Directors, effective January 1, 2001.
10-67	Second Amendment to the DTE Energy Company Deferred Stock Compensation Plan for Non-Employee Directors, effective January 1, 2005.
10-68	Third Amendment to the DTE Energy Company Deferred Stock Compensation Plan for Non-Employee Directors, effective January 1, 2006.
10-69	Third Amendment to the DTE Energy Company Executive Deferred Compensation Plan, effective December 31, 2006.
10-70	First Amendment to the DTE Energy Company Supplemental Retirement Plan, effective January 1, 2002.
12-39	Computation of Ratio of Earnings to Fixed Charges.
21-2	Subsidiaries of the Company
23-19	Consent of Deloitte & Touche LLP.
31-29	Chief Executive Officer Section 302 Form 10-K Certification of Periodic Report.
31-30	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 the 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 the 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 BNY Midwest Trust Company, as successor trustee (Exhibit 4.1 to Registration Statement on Form S-3 (File No. 333-58834)).
4(b)	Third Supplemental Indenture, dated as of April 9, 2001, among DTE Capital Corporation, DTE Energy Company and BNY Midwest Trust Company, as successor trustee (Exhibit 4-225 to Form 10-Q for the quarter ended March 31, 2001).
4(c)	Supplemental Indenture, dated as of May 30, 2001, between DTE Energy Company and BNY

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Midwest Trust Company as successor trustee (Exhibit 4-226 to Form 10-Q for the quarter ended June 30, 2001). (6.45% Senior Notes due 2006 and 7.05% Senior Notes due 2011).

4(d)	Supplemental Indenture, dated as of April 5, 2002 between DTE Energy Company and BNY Midwest Trust Company, as successor trustee (Exhibit 4-230 to Form 10-Q for the quarter ended March 31, 2002). (2002 Series A 6.65% Senior Notes due 2009).
4(e)	Sixth Supplemental Indenture, dated as of June 25, 2002, between DTE Energy Company and BNY Midwest Trust Company, as successor trustee (Exhibit 4-233 to Form 10-Q for the quarter ended June 30, 2002). (4.60% Senior Notes due 2007).
4(f)	Supplemental Indenture, dated as of April 1, 2003, between DTE Energy Company and BNY Midwest Trust Company, as successor trustee, creating 2003 Series A 6 3/8% Senior Notes due 2033 (Exhibit 4(o) to Form 10-Q for the quarter ended March 31, 2003). (2003 Series A 6 3/8% Senior Notes due 2033).
4(g)	Supplemental Indenture, dated as of May 15, 2006, between DTE Energy Company and BNY Midwest Trust Company, as successor trustee (Exhibit 4-239 to Form 10-Q for the quarter ended June 30, 2006). (2006 Series B 6.35% Senior Notes due 2016).
4(h)	Amended and Restated Trust Agreement of DTE Energy Trust I, dated as of January 15, 2002 (Exhibit 4-229 to Form 10-K for the year ended December 31, 2001).
4(i)	Amended and Restated Trust Agreement of DTE Energy Trust II, dated as of June 1, 2004 (Exhibit 4(q) to Form 10-Q for the quarter ended June 30, 2004).
4(j)	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 the 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 the 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 the 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 the 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 the 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 the 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 the 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 the quarter ended March 31, 1998).
10(j)	DTE Energy Company Annual Incentive Plan (Exhibit 10-44 to Form 10-Q for the quarter ended Maech 31, 2001).

10(k)	DTE Energy Company 2001 Stock Incentive Plan (Exhibit 10-43 to Form 10-Q for the quarter ended March 31, 2001).
10(l)	DTE Energy Company 2006 Long-Term Incentive Plan (Annex A to DTE Energy's Definitive Proxy Statement dated March 24, 2006).
10(m)	DTE Energy Company Deferred Stock Compensation Plan for Non-Employee Directors (as amended and restated effective as of January 1, 1999) (Exhibit 10-30 to Form 10-K for the year ended December 31, 1998).
10(n)	DTE Energy Company Retirement Plan for Non-Employee Directors' Fees (as amended and restated effective as of December 31, 1998) (Exhibit 10-31 to Form 10-K for the year ended December 31, 1998).
10(o)	DTE Energy Company Plan for Deferring the Payment of Director's Fees (as amended and restated effective as of January 1, 1999) (Exhibit 10-29 to Form 10-K for the 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 the quarter ended June 30, 2002).
10(q)	Amendment to the DTE Energy Company Supplemental Savings Plan (Exhibit 10-54 to Form 10-Q for the 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 the quarter ended June 30, 2002).
10(s)	First Amendment to the DTE Energy Company Executive Deferred Compensation Plan (Exhibit 10-61 to Form 10-K for the year ended December 31, 2005).
10(t)	Second Amendment to the DTE Energy Company Executive Deferred Compensation Plan (Exhibit 10-55 to Form 10-Q for the quarter ended September 30, 2004).
10(u)	DTE Energy Company Supplemental Retirement Plan, effective as of January 1, 2002 (Exhibit 10-46 to Form 10-Q for the quarter ended June 30, 2002).
10(v)	Amendment to the DTE Energy Company Supplemental Retirement Plan (Exhibit 10-53 to Form 10-Q for the quarter ended September 30, 2004).
10(w)	DTE Energy Company Executive Supplemental Retirement Plan, effective as of January 1, 2001 (Exhibit 10-51 to Form 10-Q for the quarter ended September 30, 2004).
10(x)	First Amendment to the DTE Energy Company Executive Supplemental Retirement Plan (Exhibit 10-52 to Form 10-Q for the quarter ended September 30, 2004).
10(y)	Second Amendment to the DTE Energy Company Executive Supplemental Retirement Plan (Exhibit 10-60 to Form 10-K for the year ended December 31, 2005).
10(z)	Third Amendment to the DTE Energy Company Executive Supplemental Retirement Plan (Exhibit 10-65 to Form 10-Q for the quarter ended September 30, 2006).
10(aa)	The Detroit Edison Company Supplemental Long-Term Disability Plan, dated January 27, 1997 (Exhibit 10-4 to Form 10-K for the year ended December 31, 1996).
10(bb)	Description of Executive Life Insurance Plan (Exhibit 10-47 to Form 10-Q for the quarter ended June 30, 2002).
10(cc)	Executive Vehicle Plan of The Detroit Edison Company, dated as of September 1, 1999 (Exhibit 10-41 to Form 10-Q for the quarter ended March 31, 2001).
10(dd)	DTE Energy Affiliates Nonqualified Plans Master Trust, effective as of May 1, 2003 (Exhibit 10-49 to Form 10-Q for the quarter ended March 31, 2003).

10(ee)	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 the year ended December 31, 2004).
10(ff)	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(gg)	Amendment No. 1 to Five-Year Credit Agreement, dated as of January 10, 2007, by and among, DTE Energy Company, 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 January 10, 2007).
10(hh)	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(ii)	Amendment No. 1 to Second Amended and Restated Five-Year Credit Agreement, dated as of January 10, 2007 by and among DTE Energy Company, the lenders party thereto, and Citibank, N.A., as Administrative Agent and Barclays Bank PLC and JP Morgan Chase Bank, N.A., as Co-Syndication Agents (Exhibit 10.2 to Form 8-K dated January 10, 2007).
10(jj)	Form of Director Restricted Stock Agreement (Exhibit 10.1 to Form 8-K dated June 23, 2005).
10 kk)	Form of Director Restricted Stock Agreement pursuant to the DTE Energy Company Long-Term Incentive Plan (Exhibit 10.1 to Form 8-K dated June 29, 2006).
99(a)	Master Trust Agreement (“Master Trust”), dated as of June 30, 1994, between DTE Energy Company, as successor, and Fidelity Management Trust Company relating to the Savings and Investment Plans (Exhibit 4-167 to Form 10-Q for the 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 the 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 the 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 the 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 the 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 the 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 the 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 the 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 the 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 the 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 the 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 the year ended December 31, 2004).
(iii)	**Exhibits furnished herewith.**
32-29	Chief Executive Officer Section 906 Form 10-K Certification of Periodic Report.
32-30	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, 2006	2005	2004
Allowance for Doubtful Accounts (shown as deduction from Accounts Receivable in the Consolidated Statement of Financial Position)			
Balance at Beginning of Period	**$ 136**	$ 129	$ 99
Additions:			
Charged to costs and expenses	**120**	106	108
Charged to other accounts (1)	**7**	9	9
Deductions (2)	**(93)**	(108)	(87)
Balance At End of Period	**$ 170**	$ 136	$ 129

(1) Collection of accounts previously written off.

(2) Uncollectible accounts written off.

(in Millions)	Year Ending December 31, 2006	2005	2004
Note Receivable Reserve			
Balance at Beginning of Period	**$ —**	$ —	$ —
Additions:			
Charged to costs and expenses — shown as deduction in the Consolidated Statement of Financial Position from:			
Other Current Assets	**50**	—	—
Notes Receivable	**15**	—	—
Deductions	**—**		
Balance At End of Period	**$ 65**	$ —	$ —

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 1, 2007

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 Vice President and Controller, and Chief Accounting Officer	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/ JOHN E. LOBBIA John E. Lobbia, Director	By /s/ JAMES H. VANDENBERGHE James H. Vandenberghe, Director

Date: March 1, 2007

EXHIBIT 10.66

FIRST AMENDMENT TO THE DTE ENERGY COMPANY DEFERRED STOCK COMPENSATION PLAN FOR NON-EMPLOYEE DIRECTORS

RECITALS

A. DTE Energy Company (the "Company") adopted the DTE Energy Company Deferred Stock Compensation Plan for Non-Employee Directors (the "Plan") to enable the Company to attract and retain Directors.

B. The Company's Board of Directors (the "Board") is authorized to amend the Plan.

C. By a resolution properly adopted on June 27, 2001, the Board amended the Plan to increase the number of hypothetical shares of Company stock annually credited to Directors under the Plan.

PLAN AMENDMENT

Effective January 1, 2001, the DTE Energy Company Deferred Stock Compensation Plan for Non-Employee Directors is amended as follows:

Section III is replaced in its entirety with the following:

Each Director participating in the Plan who is a Director on the first business day of a calendar year beginning on or after January 1, 2001 shall receive automatically on such date as a credit to an unfunded deferred stock account established for the Director under Section IV below, 1,000 hypothetical shares of Company Common Stock.

CERTIFICATE OF SECRETARY OF DTE ENERGY COMPANY

I, Sandra Kay 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 Board of Directors of the Company held on June 27, 2001, the Board of Directors adopted the above amendment.

/s/ Sandra Kay Ennis

Sandra Kay Ennis

February 19, 2007

Date

EXHIBIT 10.67

SECOND AMENDMENT TO THE DTE ENERGY COMPANY DEFERRED STOCK COMPENSATION PLAN FOR NON-EMPLOYEE DIRECTORS

RECITALS

A. DTE Energy Company (the "Company") adopted the DTE Energy Company Deferred Stock Compensation Plan for Non-Employee Directors (the "Plan") to enable the Company to attract and retain Directors.

B. The Company's Board of Directors (the "Board") is authorized to amend the Plan.

C. By a resolution properly adopted on January 27, 2005, the Board amended the Plan to increase the number of hypothetical shares of Company stock annually credited to Directors under the Plan.

PLAN AMENDMENT

Effective January 1, 2005, the DTE Energy Company Deferred Stock Compensation Plan for Non-Employee Directors is amended as follows:

Section III is replaced in its entirety with the following:

Each Director participating in the Plan who is a Director on the first business day of a calendar year beginning on or after January 1, 2005 shall receive automatically on January 27, 2005 for the 2005 calendar year and as of the first business day of a calendar year beginning after 2005 as a credit to an unfunded deferred stock account established for the Director under Section IV below, 1,250 hypothetical shares of Company Common Stock.

CERTIFICATE OF SECRETARY OF DTE ENERGY COMPANY

I, Sandra Kay 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 Board of Directors of the Company held on January 27, 2005, the Board of Directors adopted the above amendment.

/s/ Sandra Kay Ennis

Sandra Kay Ennis

February 19, 2007

Date

EXHIBIT 10.68

THIRD AMENDMENT TO THE DTE ENERGY COMPANY DEFERRED STOCK COMPENSATION PLAN FOR NON-EMPLOYEE DIRECTORS

RECITALS

A. DTE Energy Company (the "Company") adopted the DTE Energy Company Deferred Stock Compensation Plan for Non-Employee Directors (the "Plan") to enable the Company to attract and retain Directors.

B. The Company's Board of Directors (the "Board") is authorized to amend the Plan.

C. By a resolution properly adopted on November 17, 2005, the Board amended the Plan to increase the number of hypothetical shares of Company stock annually credited to Directors under the Plan.

PLAN AMENDMENT

Effective January 1, 2006, the DTE Energy Company Deferred Stock Compensation Plan for Non-Employee Directors is amended as follows:

Section III is replaced in its entirety with the following:

Each Director participating in the Plan who is a Director on the first business day of a calendar year beginning on or after January 1, 2006 shall receive automatically on such date as a credit to an unfunded deferred stock account established for the Director under Section IV below, 1,750 hypothetical shares of Company Common Stock.

CERTIFICATE OF SECRETARY OF DTE ENERGY COMPANY

I, Sandra Kay 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 Board of Directors of the Company held on November 17, 2005, the Board of Directors adopted the above amendment.

/s/ Sandra Kay Ennis

Sandra Kay Ennis

February 19, 2007

Date

EXHIBIT 10.69

THIRD AMENDMENT TO THE DTE ENERGY COMPANY EXECUTIVE DEFERRED COMPENSATION PLAN

The DTE Energy Company Executive Deferred Compensation Plan is amended as follows, effective December 31, 2006:

1. New Section 4.01(c) is added as follows:

   (c) No Deferrals Permitted After December 31, 2006. No Eligible Employee may elect to defer any Performance Shares payable after December 31, 2006.

2. New Section 4.03(c) is added as follows:

   (d) No Deferrals Permitted After December 31, 2006. No Eligible Employee may elect to defer any Annual Cash Bonus payable after December 31, 2006.

Amendment adopted by Organization and Compensation Committee on October 30, 2006.

Amendment effective December 31, 2006.

CERTIFICATE OF SECRETARY OF DTE ENERGY COMPANY

I, Sandra Kay 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 of the Board of Directors of the Company held on October 30, 2006, the Board of Directors adopted the above amendment.

/s/ Sandra Kay Ennis

Sandra Kay Ennis

February 19, 2007

Date

EXHIBIT 10.70

FIRST AMENDMENT TO THE DTE ENERGY COMPANY SUPPLEMENTAL RETIREMENT PLAN (EFFECTIVE AS OF JANUARY 1, 2002)

The First Amendment to the DTE Energy Company Supplemental Retirement Plan is adopted pursuant to resolutions approved by the Benefit Plan Administration Committee on September 29, 2003.

1. Effective as of October 1, 2003, Article 5 "Eligibility" shall be amended and restated to read as follows:

SECTION 5.1. PARTICIPANTS.

(a) In General. Except as noted in Section 5.1(b), each employee of a Participating Employer who is included within the term "select group of management or highly compensated employees" within the meaning of Title 1 of ERISA and whose benefits have been limited as described in Section 6.1 or 6.2, shall be eligible for benefits under the Plan.

(b) 415 Limits. A Participant of a Participating Employer whose benefits under the Qualified Plan are limited because of the limitation on benefits and contributions under Section 415 of the Code shall be eligible for the benefits provided by this Plan.

(c) Qualified Plan Eligibility. Notwithstanding the foregoing, no employee shall be eligible for benefits provided by this Plan until such employee has satisfied the eligibility requirements of the Qualified Plan.

SECTION 5.2. DETERMINATION OF ELIGIBILITY. The Vice President, Human Resources shall designate employees as eligible for participation under Section 5.1(a). The Vice President, Human Resources may revoke such designation prior to any Plan Year with respect to the employee's eligibility for benefits for such Plan Year, provided, however, that no such revocation shall adversely affect any amounts previously credited to such employee under the Plan.

2. Effective as of January 1, 2004, Article 6 "Employers' Obligation" shall be amended and restated to read as follows:

SECTION 6.1. QUALIFIED PLAN BENEFIT. The Participating Employers shall pay under this Plan any amount that any eligible employee would have been entitled to receive under the Qualified Plan but for the limitation on compensation under Section 401(a)(17) of the Code, the limitation on benefits and contributions under Section 415 of the Code, and any other provision of the Code or other law that the Committee hereafter designates. Also, the Participating Employer shall pay under this Plan any amount that any eligible employee would have been entitled to receive under the Qualified Plan but for the exclusion of deferrals under the DTE Energy Company Supplemental Savings Plan and the DTE Energy Company Executive Deferred

Compensation Plan from the definition of compensation under the option of the Qualified Plan applicable to such Participant.

SECTION 6.2 EXECUTIVE DEFERRED COMPENSATION PLAN BENEFIT. The Participating Employers shall credit hypothetical bookkeeping accounts ("Make-Up Account") for each Participant with amounts intended to replace benefits (but not earnings) under any plan maintained by a Participating Employer which is intended to be qualified under Code section 401(a) which are reduced as a result of any deferrals under Sections 4.01, 4.02, or 4.03 of the DTE Energy Company Executive Deferred Compensation Plan ("EDCP"):

(a) Traditional Pension Plan Make-Up. The Participating Employer shall credit to the Participant's Make-Up Account, an amount equal to the difference between (i) the present value, determined under each applicable defined benefit plan maintained by a Participating Employer which is intended to be qualified under Code section 401(a), including the MCN Traditional Option and the DTE Traditional Option of the Qualified Plan ("Pension Plan"), of the benefit that the Participant would have been entitled to receive under each such Pension Plan but for his election to defer any amount under the EDCP, and (ii) the present value, determined under each such Pension Plan, of the benefit that the Participant is entitled to receive under such Pension Plan. Such contribution shall be determined and credited as of the Participant's date of termination of employment.

(b) Cash Balance Pension Plan Make-Up. The Participating Employer shall credit to the Participant's Make-Up Account an amount equal to the additional increment that would have been added to the Participant's account under a cash balance defined benefit plan maintained by any Participating Employer which is intended to be qualified under Code section 401(a), excluding the MCN Traditional Option and the DTE Traditional Option of the Qualified Plan ("Cash Balance Plan"), but for his election to defer any amount under the EDCP. Such contribution shall be determined and credited as of the last day of each calendar year.

SECTION 6.3. PRIOR PLAN PAYMENTS. If a Participant is in pay status as of December 31, 2001 under one of the Prior Plans, or has terminated employment from a Participating Employer prior to January 1, 2002, the amount and method of payment to such Participant shall continue under the provisions of the applicable Prior Plan. Such payments shall be made by the Participating Employer who last employed the Participant.

3. Effective as of October 1,2003, Subsection (a) of Section 7.1 "Form and Timing of Payment" shall be amended and restated to read as follows:

(a) Form of Payment. As of the end of the quarter in which his or her Termination Date occurs, the Participant's Plan benefit shall be present-valued in accordance with the methodology set forth in the portion of the Qualified Plan in which the Participant participates. Payment of a Participant's Plan benefit shall be made in cash in accordance with the Participant's selection on his or her Distribution Election Form either as (1) a joint and 100% survivor annuity, (2) a joint and 50% survivor annuity, (3) a single life annuity or (4) in annual payments over a period not less than one year and not more than 15 years as selected by the Participant. If a Participant has not elected a payment option while he or she is actively employed by the Company or a Participating Employer, distribution shall be made as a joint and 50% survivor annuity for Participants who are married as of the Participant's Termination Date and as a single life annuity for Participants who are single as of the Participant's Termination Date.

4. Effective as of October 1, 2003, Subsection (b) of Section 7.1 "Form and Timing of Payment" shall be amended and restated to read as follows:

(b) Timing of Payment. A lump sum distribution shall be made as of March 1 following the Termination Date 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 whose employment has terminated for any reason other than death has elected to receive his or her distribution in the form of an annuity, the timing of the first payment shall be consistent with the timing for annuity payments specified in the portion of the Qualified Plan in which the Participant participates. If a Participant has elected to receive his or her distribution in annual installments, the first installment shall be made as of March 1 following the Participant's Termination Date 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. The amount of any annual payments shall be calculated to pay out over the specified period the Participant's Plan benefit as of his or her Termination Date with interest credited annually on the declining balance at the Plan Interest Rate. The amount of the annual payments to the Participant shall be adjusted as of each December 31 to reflect changes in the Plan Interest Rate.

5. Effective as of October 1,2003, Section 7.3 "Recomputation of Plan Benefits Upon Reemployment" shall be amended and restated to read as follows:

SECTION 7.3. RECOMPUTATION OF PLAN BENEFITS UPON REEMPLOYMENT. If a Participant entitled to a distribution under the qualified Plan receives all or part of his or her Plan benefit and is thereafter reemployed, such Participant's Plan benefit shall be recalculated upon the Participant's subsequent termination of employment. Plan payments shall cease upon reemployment. If a Participant's recalculated Plan benefit

results in an additional payment to the Participant, such additional payment shall be made in accordance with Section 7.1. Such recalculations shall be made in accordance with the procedures under the Qualified Plan. If such Participant's recalculated Plan benefit shows that the Participant's Plan benefit has been overpaid after offsetting for any Plan benefits previously received, the Participant shall be required to make restitution to the Participating Employer, within a period of twelve months of such subsequent termination, in an amount equal to such overpayment, plus interest at the Plan Interest Rate.

6. Effective as of October 1, 2003, Article 8 "Beneficiary in the Event of Death" shall be amended and restated to read as follows:

SECTION 8.1. DEATH AFTER COMMENCEMENT OF BENEFITS. If a Participant dies after payment of his or her Plan benefit begins in accordance with Section 7.1, the undistributed balance to which such Participant would have been entitled, if any, shall continue to be distributed to the Participant's beneficiary (as designated under Section 8.3) in accordance with the method of distribution being used prior to the Participant's death.

SECTION 8.2. DEATH PRIOR TO COMMENCEMENT OF BENEFITS. If a Participant dies before distribution of his or her Plan benefit begins in accordance with Section 7.1, the Participant's Plan benefit, if any, shall be determined in accordance with the surviving spouse provisions of the portion of the Qualified Plan in which the Participant participated prior to his or her death.

SECTION 8.3. BENEFICIARY DESIGNATION. Each Participant who has elected to receive his or her distribution in the form of a joint and 100% survivor annuity or joint and 50% survivor annuity shall have the right to designate a contingent annuitant to receive the survivor portion of the annuity payment upon the death of such Participant. Each Participant who has elected to receive his or her distribution in the form of annual payments over a period of one to 15 years shall have the right to designate a beneficiary or beneficiaries to receive any undistributed annual payments upon the death of such Participant. Any Participant who has elected to receive his or her distribution in the form of a single life annuity shall not be allowed to designate a beneficiary and benefit payments will cease upon the Participant's death.

This First Amendment to the DTE Energy Company Supplemental Retirement Plan is executed as of September 29, 2003.

DTE ENERGY COMPANY

By: /s/ Larry E. Steward

Larry E. Steward
Vice President, Human Resources

DTE ENERGY COMPANY
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

(Millions of Dollars)	2006	2005	2004	2003	2002
	Twelve Months Ended December 31				
Earnings:					
Pretax earnings	$ 324	$ 498	$ 428	$ 257	$ 479
Adjustments	(4)	5	2	26	24
Fixed charges	559	547	544	569	557
Net earnings	$ 879	$ 1,050	$ 974	$ 852	$ 1,060
Fixed charges:					
Interest expense	$ 526	$ 519	$ 516	$ 545	$ 553
Adjustments	33	28	28	24	4
Fixed charges	$ 559	$ 547	$ 544	$ 569	$ 557
Ratio of earnings to fixed charges	1.57	1.92	1.79	1.50	1.90

Exhibit 21-2

SUBSIDIARIES OF DTE ENERGY COMPANY

DTE Energy Company's principal subsidiaries as of December 31, 2006 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 23-19

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference of our reports dated March 1, 2007, 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 defined benefit pension and other postretirement plans and share based payments in 2006 and asset retirement obligations in 2005) 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, 2006, 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-3	333-136815-02
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
Form S-8	333-133645

Detroit, Michigan
March 1, 2007

/S/ DELOITTE & TOUCHE LLP

Detroit, Michigan

Exhibit 31-29

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 1, 2007

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 1, 2007

David E. Meador
Executive Vice President and
Chief Financial Officer of DTE Energy Company

Exhibit 32-29

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, 2006, 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 1, 2007

/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.

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, 2006, 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 1, 2007

/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.