DTE ENERGY CO
Form 10-Q
August 14, 2007

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q
QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the Quarterly Period ended June 30, 2007
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)

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 þ **No** o

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).

Large accelerated filer þ Accelerated filer o Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes o **No** þ

At June 30, 2007, 170,649,715 shares of DTE Energy s Common Stock, substantially all held by non-affiliates, were outstanding.

DTE Energy Company
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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) 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 Transmission	International Transmission Company (until February 28, 2003, a wholly owned subsidiary of DTE Energy)
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
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.

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Proved Reserves	Estimated quantities of natural gas, natural gas liquids and crude oil that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reserves under existing economic and operating conditions.
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.
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

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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, including potential new federal and state requirements that could include carbon and more stringent mercury emission controls, a renewable portfolio standard and energy efficiency mandates;
- nuclear regulations and operations associated with nuclear facilities;
- impact of electric and gas Customer Choice programs;
- impact of electric and gas utility restructuring in Michigan, including legislative amendments;
- employee relations, and the negotiation and impacts 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;

timing, terms and proceeds from any asset sale or monetization; and

implementation of new processes and new core information systems.

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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.

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DTE Energy Company
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.

Net income in the second quarter of 2007 was $385 million, or $2.20 per diluted share, compared to a net loss of $33 million, or $.19 per diluted share, in the second quarter of 2006. Net income for the six months ended June 30, 2007 was $519 million, or $2.95 per diluted share, compared to net income of $103 million, or $.58 per diluted share in the comparable period for 2006. The increases were due, in part, to $359 million in net income resulting from the gain on the sale of the Antrim shale gas exploration and production business of $897 million ($569 million after-tax), partially offset by losses recognized on related hedges of $323 million ($210 million after-tax), including income statement recognition of amounts previously recorded in other comprehensive income. The 2006 results reflect significant reserves and impairments associated with our synfuel operations.

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

- Effects of weather and collectibility of accounts receivable on utility operations;
- Impact of regulatory decisions on our utility operations;
- Monetization of our Unconventional Gas Production business;
- Monetization of our Power and Industrial Projects business;
- Results in our Energy Trading business;
- Synfuel-related earnings; and
- Cost reduction efforts and required capital investment.

UTILITY OPERATIONS

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

Our Gas Utility segment consists of MichCon and Citizens Fuel Gas Company (Citizens). 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. Citizens distributes natural gas in Adrian, Michigan to approximately 17,000 customers.

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 the six months ended June 30, 2007, we experienced colder weather in the initial three months in comparison to the comparable period of 2006, while we experienced warmer weather during the second quarter of 2007 compared to the corresponding period of 2006.

Receivables - Both utilities continue to experience high levels of past due receivables, especially within our Gas Utility operations, primarily attributable to economic conditions and a lack of adequate levels of assistance for low-income customers.

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We have taken aggressive actions to reduce the level of past due receivables, including increasing 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. While our levels of past due receivables remain high, our allowance for doubtful accounts expense for the two utilities remained the same at approximately $39 million for each of the three months ended June 30, 2007 and 2006. We experienced an $11 million decrease in allowance for doubtful accounts expense to approximately $68 million during the six months ended June 30, 2007, in comparison to $79 million during the six months ended June 30, 2006.

The April 2005 MPSC gas rate order provided for an uncollectible true-up mechanism for MichCon. The uncollectible true-up mechanism enables MichCon to recover ninety percent of the difference between the actual uncollectible expense for each year and $37 million after an annual reconciliation proceeding before the MPSC. The MPSC approved the 2005 annual reconciliation on December 21, 2006, allowing MichCon to surcharge $11 million beginning in January 2007. We filed the 2006 annual reconciliation with the MPSC in the first quarter of 2007, requesting recovery of $34 million. The following table provides the current amount outstanding and status of each respective year:

(in Millions) Year	Balance at June 30, 2007	Balance at December 31, 2006	Current Regulatory Filing Status
2005 (1)	$ 6	$ 11	Approved in December 2006; actively billing customers
2006 (2)	34	34	Reconciliation filed with the MPSC in March 2007
2007 (2)	22		Accruing; reconciliation filing scheduled for first quarter 2008
Total	$ 62	$ 45	

(1) Classified as a current unbilled accounts receivable

(2) Classified as a long-term regulatory asset

Regulatory activity Detroit Edison filed a general rate case on April 13, 2007 based on a 2006 historical test year. The filing with the MPSC requests a $123 million, or 2.9 percent average increase, in Detroit Edison s annual revenue requirement for 2008. See Note 6 of the Notes to Consolidated Financial Statements.

The MPSC issued an order on August 31, 2006 approving a settlement agreement providing for an annualized rate reduction of $53 million for 2006 for Detroit Edison, effective September 5, 2006. Beginning January 1, 2007, and continuing until April 13, 2008, one year from the filing of the general rate case on April 13, 2007, rates were reduced by an additional $26 million, for a total reduction of $79 million annually. Detroit Edison experienced a rate reduction of approximately $17 million and $34 million in the three and six months ended June 30, 2007, respectively, 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 of the rate reduction to the commercial and industrial customer classes than to the residential customer classes.

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, skills 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 and impairments from certain power generation assets, 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 have taken and are considering various actions including the sale, restructuring or recapitalization of certain non-utility businesses which we expect may generate approximately $1.5 billion in after-tax cash proceeds in 2007. See Note 4 of the Notes to Consolidated Financial Statements for information on the sale of our Antrim shale gas exploration and production business in northern Michigan and the pending sale of a 50 percent ownership interest in select projects within the Power and Industrial Projects segment.

The primary source of recent investment capital in our non-utility operations has been cash flow from the synfuel business. See the Outlook section for information on sources of cash flows from the synfuel business.

Coal and Gas Midstream

Our Coal and Gas Midstream segment 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.

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 was referred to arbitration. Under this contract, BNSF transports western coal east for Detroit Edison and the Coal Transportation and Marketing business. We filed a breach of contract claim against BNSF for the failure to provide certain services that we believe are required by the contract. We received a partial decision from the arbitration panel in August 2007 which held that BNSF is required to provide such services under the contract. A final decision, which will be subject to an appeal process, is expected in the third quarter of 2007. While we believe that the arbitration panel s decision will be upheld if it is appealed, a negative decision on appeal could have an adverse effect on our ability to grow the Coal Transportation and Marketing business as currently contemplated.

Pipelines, Processing and Storage owns a partnership interest in two interstate transmission pipelines, four 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.

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

Unconventional Gas Production

Our Unconventional Gas Production business is engaged in natural gas exploration, development and production primarily within the Barnett shale in north Texas.

On June 29, 2007, we sold our Antrim shale gas exploration and production business in the northern lower peninsula of Michigan to Atlas Energy Resources LLC for $1.258 billion, subject to routine post close adjustments. See Note 4 of the Notes to Consolidated Financial Statements.

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In the first six months of 2007, we continued to expand our operations in the Barnett shale basin in north Texas, where recent leasehold acquisitions have increased our total leasehold acreage to 93,418 acres (83,930 net of interest of others). Current natural gas prices provide attractive opportunities for our Unconventional Gas Production business segment.

In the second quarter of 2007, our Unconventional Gas Production segment recorded a pre-tax impairment loss of $9 million related to the write-off of unproved properties in Bosque County, which is located in the southern expansion area of the Barnett shale basin, and the write-off of costs associated with various leases expiring in the third quarter of 2007. The properties were impaired due to the lack of economic and operating viability of the project. See Note 5 of the Notes to Consolidated Financial Statements.

In August 2007, we announced that we are exploring opportunities to monetize a portion of our interests in the Barnett shale. We anticipate significant opportunities in our existing Barnett shale acreage. We are currently in the test and development phase for unproven and recently acquired Barnett shale acreage.

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 experienced Barnett shale personnel provide an advantage in addressing potential cost increases. We invested approximately $90 million ($70 million in the Barnett shale and $20 million in the Antrim shale) in the first six months of 2007 and expect to invest up to $80 million in the Barnett shale during the remainder of 2007.

As a component of our risk management strategy for our Barnett shale reserves, we hedged a portion of our reserves to secure an attractive investment return. As of June 30, 2007, we have a series of cash flow hedges for approximately 8 Bcf of anticipated Barnett gas production through 2010 at an average price of $7.64 per Mcf.

Power and Industrial Projects

Power and Industrial Projects is comprised primarily of projects that deliver energy and utility-type products and services to industrial, commercial and institutional customers, and biomass energy projects. This segment provides utility-type services using project assets usually located on or near 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. At June 30, 2007, this segment owned and operated three gas-fired peaking electric generating plants and a biomass-fired electric generating plant and also operated one additional coal-fired power plant under contract. Additionally, this segment owns a gas-fired peaking electric generating plant that was taken out of service in September 2006. This segment develops, owns and operates landfill gas recovery systems throughout the United States. In addition, this segment produces metallurgical coke from two coke batteries. The production of coke from these coke batteries generates production tax credits.

We have agreed to sell a 50 percent interest in a portfolio of select Power and Industrial Projects. Immediately prior to the sale of the equity interest, the company that will own the portfolio of projects will obtain debt financing and the proceeds will be distributed to us. The total gross proceeds we will receive are expected to be approximately $800 million. The sale is subject to normal closing conditions and the receipt of satisfactory financing arrangements. The transaction is expected to close in the second half of 2007. We plan to account for our 50 percent ownership interest in the company that will own the portfolio of projects using the equity method. See Note 4 of the Notes to Consolidated Financial Statements. In July 2007, we sold our Georgetown peaking electric generating facility. In July 2007, we entered into an agreement to sell our 50 percent interest in Crete, a 320 MW natural gas-fired peaking electric generating plant. The sale of the Crete interest is subject to receipt of regulatory approval and is expected to close in the second half of 2007. See Note 4 of the Notes to Consolidated Financial Statements.

Energy Trading

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, 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.

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. We have completed a review of strategic options for this business and have decided to retain and continue to grow our energy trading business.

Synthetic Fuel

Synthetic Fuel Operations

We are the operator of nine synthetic fuel production facilities throughout the United States. 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, assuming no phase-out. 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.

Recognition of Synfuel Gains

To optimize income and cash flow from the synfuel operations, we have sold interests in all nine of the facilities, representing 91 percent of the total production capacity as of June 30, 2007. 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, assuming no phase-out.

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The gain from the sale of synfuel facilities is comprised of fixed and variable components. The fixed component represents note payments, is generally 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.

Contractual Partners Obligations

Our partners reimburse us (through the project entity) for the operating losses of the synfuel facilities. The reimbursements are 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. Reserves established for an expected 2007 tax credit phase out, net of adjustments primarily resulting from the issuance of the final 2006 Reference Price by the IRS, had the effect of reducing the reserve balance by $4 million and $10 million in the three and six months ended June 30, 2007, respectively. This compares with increasing reserves by $85 million and $125 million in the three and six months ended June 30, 2006, respectively.

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 2007, the annual average wellhead price is projected to be approximately $6 less 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 2006 and 2007 are as follows:

	Reference Price	Beginning Phase-Out Price	Ending Phase-Out Price
2006 (actual)	$ 59.68	$ 55.06	$ 69.12
2007 (estimated)	$ 60	$ 56	$ 71

The NYMEX daily closing price of a barrel of oil for the six months ended June 30, 2007 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 2007 will not be certain until the Reference Price is published by the IRS in April 2008. 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 mark-to-market with changes in fair value recorded as an adjustment to synfuel gains. The derivative contracts involve purchased and written call options covering a specified number of barrels of oil that provide for net cash settlement at expiration based on the 2007 calendar year 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 losses of $24 million and $20 million during the three and six months ended June 30, 2007, respectively, and gains of $60 million and $107 million during the three and six months ended June 30, 2006, respectively. The fair value changes are recorded as adjustments to the gain from selling interests in synfuel facilities and are included in the Other 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 June 30, 2007, we paid approximately $113 million for 2007 hedges which will provide protection for a significant portion of our cash flows related to synfuel production during 2007.

Risks and Exposures

Since there is a likelihood that the Reference Price for a barrel of oil will reach the threshold at which synfuel-related production tax credits began to phase-out, we defer gain recognition associated with variable and fixed note payments until the probability of refund is remote and collectibility is assured. All or a portion of the deferred gains will be recognized when and if the gain recognition criteria is met. Fixed gains recognized totaled $25 million and $58 million during the three and six months ended June 30, 2007, respectively, compared to the recognition of fixed gains of $8 million and $30 million during the three and six months ended June 30, 2006, respectively. During the three and six months ended June 30, 2007, variable gains recognized totaled $26 million and $32 million, respectively, whereas we recognized variable gains totaling $17 million and $9 million, respectively, for the comparable 2006 periods. Synfuel results recognized were impacted by adjustments to prior year gains and reserves to reflect issuance of the final Reference Prices by the IRS.

Additionally, we establish reserves for potential refunds of amounts related to partners capital contributions associated with operating losses allocated to their account. 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. During the six months ended June 30, 2007, we refunded approximately $16 million to our partners.

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, 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. A significant portion of the expected cash flow 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 inability to generate new production tax credits after 2007 and the resulting discontinuance of synfuel production. We have fixed notes receivable 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 and 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 rates 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 required to provide safe, reliable and affordable energy. 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. In order to fully realize the benefits from the Performance Excellence Process, it is necessary to make significant up-front investments in our infrastructure and business processes. The 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 began 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. Amortization of prior year deferred CTA costs amounted to $3 million and $5 million during the three and six months ended June 30, 2007, respectively. During the three and six months ended June 30, 2007, CTA costs of $8 million and $21 million, respectively, were deferred. MichCon cannot defer CTA costs at this time because a regulatory recovery mechanism has not been established by the MPSC.

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 segment currently expects to invest approximately $4.3 billion (excluding investments in new generation capacity, if any), including increased environmental requirements and reliability enhancement projects during the period of 2007 through 2011. Our gas utility segment currently expects to invest approximately $1.0 billion on system expansion, pipeline safety and reliability enhancement projects through the same period. We recently launched a six-year, approximately $330 million, advanced metering infrastructure project that involves the replacement and/or modification of some four million electric and gas customer meters. We plan to seek regulatory approval to include these capital expenditures within our regulatory rate base consistent with prior treatment.

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. The second phase of implementation began in April 2007. The implementation and operation of 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, we can provide no assurance that complications will not arise that could interrupt our operations. We expect that EBS will be fully implemented by the end of 2007 at a total capital cost of approximately $382 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.

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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, asset sales, 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 such synfuel cash and cash received 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 the second quarter of 2007 was $385 million, or $2.20 per diluted share, compared to a net loss of $33 million, or $.19 per diluted share, in the second quarter of 2006. During the six months ended June 30, 2007, our net income was $519 million, or $2.95 per diluted share, compared to net income of $103 million, or $.58 per diluted share, for the comparable period of 2006. The following sections provide a detailed discussion of the operating performance and future outlook of our segments.

Segments realigned In 2006, we realigned the non-utility segment Power and Industrial Projects business unit to separately present the Synthetic Fuel business and we separated the Fuel Transportation and Marketing segment into Coal and Gas Midstream and Energy Trading. See Note 10 of the Notes to Consolidated Financial Statements for further information on this realignment.

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(in Millions)	Three Months Ended June 30 **2007**	2006	Six Months Ended June 30 **2007**	2006
Net Income (Loss) by Segment:				
Electric Utility	**$ 60**	$ 57	**$ 100**	$ 116
Gas Utility	**(7)**	(14)	**60**	36
Non-utility Operations:				
Coal and Gas Midstream	**11**	10	**23**	23
Unconventional Gas Production (1)	**(211)**	2	**(209)**	3
Power and Industrial Projects	**6**	(1)	**10**	(24)
Energy Trading	**(13)**	(23)	**(12)**	5
Synthetic Fuel	**37**	(34)	**75**	(13)
Corporate & Other (2)	**502**	(29)	**472**	(42)
Income (Loss) from Continuing Operations				
Utility	**53**	43	**160**	152
Non-utility	**(170)**	(46)	**(113)**	(6)
Corporate & Other	**502**	(29)	**472**	(42)
	385	(32)	**519**	104
Discontinued Operations		(1)		(2)
Cumulative Effect of Accounting Change				1
Net Income (Loss)	**$ 385**	$ (33)	**$ 519**	$ 103

(1) 2007 Net Loss results principally from the recognition of losses on hedge contracts associated with the Antrim sale transaction. See Note 4 of the Notes to the Consolidated Financial Statements.

(2) 2007 Net Income results principally from the gain

recognized on the Antrim sale transaction. See Note 4 of the Notes to the Consolidated Financial Statements

ELECTRIC UTILITY

Our Electric Utility segment consists of Detroit Edison.

Factors impacting income: Net income increased by $3 million in the second quarter of 2007 and decreased by $16 million for the six-month period ended June 30, 2007. The increase in the 2007 second quarter was due primarily to higher gross margins, partially offset by higher depreciation and amortization and operation and maintenance expenses. The decrease in the 2007 six month period was due primarily to increased depreciation and amortization and operation and maintenance expenses, partially offset by higher gross margins.

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(in Millions)	Three Months Ended June 30 2007	2006	Six Months Ended June 30 2007	2006
Operating Revenues	**$ 1,210**	$ 1,175	**$ 2,304**	$ 2,225
Fuel and Purchased Power	**402**	409	**756**	718
Gross Margin	**808**	766	**1,548**	1,507
Operation and Maintenance	**380**	369	**728**	713
Depreciation and Amortization	**198**	168	**380**	335
Taxes Other Than Income	**69**	65	**141**	134
Other Asset (Gains), Losses and Reserves, Net	**(1)**		**6**	
Operating Income	**162**	164	**293**	325
Other (Income) and Deductions	**72**	79	**143**	154
Income Tax Provision	**30**	28	**50**	55
Net Income	**$ 60**	$ 57	**$ 100**	$ 116
Operating Income as a Percent of Operating Revenues	**13%**	14%	**13%**	15%

Gross margin increased by $42 million in the second quarter of 2007 and increased $41 million in the six-month period ended June 30, 2007. The increases were due to the favorable impact of a May 2007 MPSC order related to the 2005 PSCR reconciliation, weather related impacts and higher margins due to returning sales from electric Customer Choice, partially offset by lower rates resulting primarily from the August 2006 settlement in the MPSC show cause proceeding and the impact of poor economic conditions. Revenues include a component for the cost of power sold that is recoverable through the PSCR mechanism.

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)	Three Months	Six Months
Weather related margin impacts	**$ 17**	**$ 25**
Return of customers from electric Customer Choice	**18**	**35**
Service territory economic performance	**(5)**	**(20)**
Impact of 2006 MPSC show cause order	**(17)**	**(34)**
Impact of MPSC 2005 PSCR reconciliation order	**34**	**34**
Other, net	**(5)**	**1**
Increase in gross margin	**$ 42**	**$ 41**

	Three Months Ended June 30		Six Months Ended June 30	
	2007	2006	**2007**	2006
Power Generated and Purchased				
(in Thousands of MWh)				
Power Plant Generation				
Fossil	**10,117**	9,206	**20,674**	18,515
Nuclear	**2,415**	922	**4,843**	3,118
	12,532	10,128	**25,517**	21,633
Purchased Power	**1,887**	3,318	**3,120**	4,832
System Output	**14,419**	13,446	**28,637**	26,465
Less Line Loss and Internal Use	**(624)**	(856)	**(1,408)**	(1,681)
Net System Output	**13,795**	12,590	**27,229**	24,784
Average Unit Cost ($/MWh)				
Generation (1)	**$ 14.75**	$ 16.41	**$ 15.09**	$ 15.48
Purchased Power	**$ 68.45**	$ 54.03	**$ 66.64**	$ 52.89
Overall Average Unit Cost	**$ 21.77**	$ 25.69	**$ 20.70**	$ 22.31

(1) Represents fuel costs associated with power plants.

	Three Months Ended June 30		Six Months Ended June 30	
(in Thousands of MWh)	**2007**	2006	**2007**	2006
Electric Sales				
Residential	**3,718**	3,514	**7,504**	7,350
Commercial	**4,871**	4,506	**9,179**	8,513
Industrial	**3,322**	3,209	**6,696**	6,363
Wholesale	**715**	702	**1,451**	1,377
Other	**89**	89	**199**	197
	12,715	12,020	**25,029**	23,800
Interconnections sales (1)	**1,080**	570	**2,200**	984
Total Electric Sales	**13,795**	12,590	**27,229**	24,784

Electric Deliveries				
Retail and Wholesale	**12,715**	12,020	**25,029**	23,800
Electric Customer Choice	**323**	984	**774**	2,347
Electric Customer Choice Self Generators (2)	**200**	127	**267**	478
Total Electric Sales and Deliveries	**13,238**	13,131	**26,070**	26,625

(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 by $11 million for the second quarter of 2007 and $15 million in the six-month period ended June 30, 2007. The increase for the quarter was due primarily to costs associated with EBS implementation of $33 million and higher corporate support expenses of $20 million, partially offset by the impact of CTA expensed last year of $37 million. The increase for the six month period is primarily due to costs associated with EBS implementation of $33 million, higher corporate support expenses of $17 million, higher storm expenses of $6 million, partially offset by the impact of CTA expensed last year of $49 million. CTA expenses were deferred beginning in the third quarter of 2006. See Note 6 of the Notes to the Consolidated Financial Statements.

Depreciation and amortization expense increased by $30 million for the second quarter of 2007 and $45 million for the six-month period ended June 30, 2007. The increase for the quarter was due primarily to increased amortization of regulatory assets of $27 million, including $17 million related to the electric Customer Choice Incentive mechanism, and higher depreciation expense of $7 million due to higher

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levels of depreciable plant. The increase for the six-month period was due primarily to increased amortization of regulatory assets of $38 million, including $17 million related to the electric Customer Choice Incentive mechanism, and higher depreciation expense of $11 million due to higher levels of depreciable plant.

Other asset (gains) losses and reserves, net were $6 million for the six-month period ended June 30, 2007, representing a reserve of $7 million for a loan guaranty related to the prior sale of Detroit Edison s steam heating business to Thermal Ventures II, LP, partially offset by a gain on sale of an asset of $1 million.

Outlook We continue to improve the operating performance of Detroit Edison. We continue to resolve outstanding regulatory issues and continue to pursue additional regulatory and/or legislative solutions for structural problems within the Michigan electric 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. We intend to seek recovery of these costs in future rate cases.

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, upgrade or co-invest in a base-load coal facility or a new nuclear plant. While we have not decided on construction of a new base-load nuclear plant, 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;
- levels of customer participation in the electric Customer Choice program; and
- potential new federal and state environmental requirements.

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

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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 monitor legislative action on some of its components. Without knowing how or if the plan will be fully implemented, we 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.

Factors impacting income: Gas Utility s net loss decreased $7 million in the 2007 second quarter and net income increased $24 million in the 2007 six-month period. The improvements were due primarily to higher gross margins, and for the six-month period, lower operation and maintenance expenses.

	Three Months Ended June 30		Six Months Ended June 30	
(in Millions)	**2007**	2006	**2007**	2006
Operating Revenues	**$ 311**	$ 234	**$ 1,185**	$ 1,111
Cost of Gas	**162**	93	**785**	728
Gross Margin	**149**	141	**400**	383
Operation and Maintenance	**113**	113	**224**	234
Depreciation and Amortization	**24**	22	**45**	46
Taxes other than Income	**15**	14	**29**	29
Other Asset (Gains), Losses and Reserves, Net		3	**3**	3
Operating Income (Loss)	**(3)**	(11)	**99**	71
Other (Income) and Deductions	**6**	10	**18**	25
Income Tax Provision (Benefit)	**(2)**	(7)	**21**	10
Net Income (Loss)	**$ (7)**	$ (14)	**$ 60**	$ 36
Operating Income (Loss) as a Percent of Operating Revenues	**(1)%**	(5)%	**8%**	6%

Gross Margins increased $8 million in the second quarter of 2007 and $17 million in the 2007 six-month period. The increase for the second quarter is due primarily to higher GCR revenues of $5 million, increased storage revenues of $3 million and the favorable effects of weather of $4 million, partially offset by an unfavorable impact in lost gas recognized of $5 million. The increase in the six-month period is due primarily to $21 million representing the favorable effects of weather in 2007 and $14 million related to an increase in midstream services including storage and transportation, partially offset by a $21 million unfavorable impact in lost gas recognized. Revenues include a component for the cost of gas sold that is recoverable through the GCR mechanism.

	Three Months Ended June 30		Six Months Ended June 30	
	2007	2006	**2007**	2006
Gas Markets (in Millions)				
Gas sales	**$ 239**	$ 168	**$ 1,012**	$ 963
End user transportation	**28**	27	**80**	72
	267	195	**1,092**	1,035
Intermediate transportation	**11**	13	**30**	29
Storage and other	**33**	26	**63**	47
	$ 311	$ 234	**$ 1,185**	$ 1,111
Gas Markets (in Bcf)				
Gas sales	**22**	18	**92**	84
End user transportation	**24**	27	**72**	71
	46	45	**164**	155
Intermediate transportation	**94**	125	**222**	289
	140	170	**386**	444

Operation and maintenance expense decreased $10 million in the 2007 six-month period. The decrease was due primarily to lower uncollectible expense attributable to improved customer payment trends resulting from increased effectiveness in collection efforts.

Depreciation and amortization expense was higher by $2 million in the second quarter of 2007 and lower by $1 million in the 2007 six-month period. The increase in the second quarter was due to higher levels of depreciable plant, while the decrease in the six-month period was due to a $3 million adjustment resulting from an MPSC order related to pipeline assets, partially offset by higher levels of depreciable plant.

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 MPSC s uncollectible true-up mechanism and GCR mechanism.

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

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

Factors impacting income: Net income was $1 million higher in the second quarter of 2007 and consistent with the 2006 comparable six-month period. The increases in operating revenues and operation and maintenance expenses reflected increased volumes related to coal marketing, coal-to-power tolling transactions and purchases and sales of emission credits. Both periods were impacted by increased interest expense related to the debt assumed in October 2006 from the acquisition of the Washington 10 gas storage field.

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(in Millions)	Three Months Ended June 30 2007	2006	Six Months Ended June 30 2007	2006
Operating Revenues	**$ 247**	$ 146	**$ 474**	$ 314
Operation and Maintenance	**228**	133	**434**	280
Depreciation and Amortization	**1**		**3**	2
Taxes other than Income	**2**		**3**	2
Other Asset (Gains), Losses and Reserves, net	**(1)**		**(1)**	
Operating Income	**17**	13	**35**	30
Other (Income) and Deductions	**(1)**	(2)	**(2)**	(5)
Income Tax Provision	**7**	5	**14**	12
Net Income	**$ 11**	$ 10	**$ 23**	$ 23

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. A portion of our Coal Transportation and Marketing revenues and net income are dependent upon our Synfuel operations. Coal Transportation and Marketing is involved in a contract dispute with BNSF Railway Company that was referred to arbitration. We received a partial decision from the arbitration panel in August 2007 which held that BNSF is required to provide certain services that should allow Coal Transportation and Marketing to grow its business. A final decision, which is subject to an appeal process, is expected in the third quarter of 2007. See Note 9 of the Notes to Consolidated Financial Statements.

Our Pipeline, Processing and Storage business expects to continue its steady growth plan. In April 2007, Washington 28 received MPSC approval to increase working gas storage capacity by over 6 Bcf to a total of 16 Bcf. In June 2007, Washington 10 received MPSC approval to develop the Shelby 2 storage field which will increase the working gas storage capacity of Washington 10 by 8 Bcf to a total of 74 Bcf. Vector Pipeline has secured long-term market commitments to support its first phase of 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 percent ownership interest in Millennium Pipeline which received FERC approval for construction and operation in December 2006. Millennium Pipeline commenced construction in June 2007 and is scheduled to be in service in late 2008. We plan to expand existing assets and develop new assets which are typically supported with long-term customer commitments.

Unconventional Gas Production

Our Unconventional Gas Production segment is primarily engaged in natural gas exploration, development and production in the Barnett shale. Prior to July 2007, we had significant natural gas properties in the Michigan Antrim shale formation. On June 29, 2007, we sold our Michigan Antrim shale gas exploration and production business to Atlas Energy Resources, LLC for $1.258 billion. The gain on sale is included in the Corporate & Other segment. See Note 4 of the Notes to Consolidated Financial Statements.

Factors impacting income: Unconventional Gas Production experienced a $211 million loss in the 2007 second quarter and a $209 million loss in the 2007 six-month period. This compares with income of $2 million and $3 million in the comparable 2006 periods. As subsequently discussed, the significant decline in results reflect the recording of $323 million in losses on financial contracts that hedged our price risk exposure.

(in Millions)	Three Months Ended June 30 **2007**	2006	Six Months Ended June 30 **2007**	2006
Operating Revenues	**$ (287)**	$ 24	**$ (259)**	$ 46
Operation and Maintenance	**14**	9	**25**	18
Depreciation, Depletion and Amortization	**7**	6	**14**	12
Taxes Other Than Income	**4**	3	**7**	6
Other Asset (Gains) and Losses, Reserves and Impairments, Net	**9**		**9**	
Operating Income (Loss)	**(321)**	6	**(314)**	10
Other (Income) and Deductions	**3**	3	**7**	6
Income Tax Provision (Benefit)	**(113)**	1	**(112)**	1
Net Income (Loss)	**$ (211)**	$ 2	**$ (209)**	$ 3

Operating revenues decreased $311 million in the 2007 quarter and $305 million in the 2007 six-month period. The declines reflect the recording of $323 million of losses on financial contracts that hedged our price risk exposure related to expected Antrim gas production and sales through 2013. These financial contracts were accounted for as cash flow hedges, with changes in estimated fair value of the contracts for the liquid forward period reflected in other comprehensive income. Upon the sale of Antrim, the financial contracts no longer qualified as cash flow hedges. The contracts were retained and assigned to Energy Trading, and offsetting financial contracts were put into place to effectively settle these positions. As a result of these transactions and market research performed by the Company, DTE gained additional insight and visibility into the value ascribed to these contracts by third party market participants for the entire duration of the contracts and accordingly recognized the fair value for the entire duration of the contracts. In conjunction with the Antrim sale and effective settlement of these contract positions Antrim reclassified amounts held in accumulated other comprehensive income and recorded the effective settlements, reducing operating revenues in the second quarter of 2007 by $323 million.

Outlook As indicated above, we sold our Antrim Shale gas exploration and production business on June 29, 2007. This sale resulted from our strategy to sell non-utility assets to allow us to monetize value from our more mature holdings. During 2006, Antrim shale production was 22 Bcfe.

In August 2007, we announced that we are exploring opportunities to monetize a portion of our interests in the Barnett shale. We anticipate significant opportunities in our existing Barnett shale acreage. We are currently in the test and development phase for unproven and recently acquired Barnett shale acreage.

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 experienced Barnett shale personnel provide an advantage in addressing potential cost increases. We invested approximately $90 million ($70 million in the Barnett shale and $20 million in the Antrim shale) in the first six months of 2007 and expect to invest up to $80 million in the Barnett shale during the remainder of 2007. During 2007, we expect Barnett Shale production of over 8 Bcfe of natural gas (excluding the impact of potential monetizations) compared with approximately 4 Bcfe in 2006.

Power and Industrial Projects

The Power and Industrial Projects segment is comprised primarily of projects that deliver energy and utility-type products and services to industrial, commercial and institutional customers, and biomass energy projects.

Factors impacting income: Net income was $6 million in the second quarter of 2007 as compared to a net loss of $1 million in the second quarter of 2006. Net income was $10 million in the 2007 six-month period as compared to a net loss of $24 million in the comparable 2006 period. The 2006 six-month period included an impairment loss of $16 million ($10 million after-tax) for the write down of fixed assets and patents at our waste coal recovery business.

	Three Months Ended June 30		Six Months Ended June 30	
(in Millions)	**2007**	2006	**2007**	2006
Operating Revenues	**$ 123**	$ 100	**$ 233**	$ 207
Operation and Maintenance	**109**	88	**199**	183
Depreciation and Amortization	**9**	11	**20**	24
Taxes other than Income	**2**	4	**6**	7
Other Asset (Gains) and Losses, Reserves and Impairments, Net				16
Operating Income (Loss)	**3**	(3)	**8**	(23)
Other (Income) and Deductions	**5**	5	**8**	10
Minority Interest	**(3)**		**(2)**	
Income Taxes				
Provision (Benefit)	**(2)**	(6)	**(1)**	(7)
Production Tax Credits	**(3)**	(1)	**(7)**	(2)
	(5)	(7)	**(8)**	(9)
Net Income (Loss)	**$ 6**	$ (1)	**$ 10**	$ (24)

Operating revenues increased $23 million in the 2007 second quarter and $26 million in the 2007 six-month period. The increases were due to higher volumes at several projects in 2007 and a one-time success fee earned in the first quarter for the sale of an asset we operated for a third party in the 2007 six-month period.

Operation and maintenance expense increased $21 million in the 2007 second quarter and $16 million in the 2007 six-month period resulting from increased costs and higher volumes at several projects.

Other asset (gains) and losses, reserves and impairments, net decreased in the 2007 six-month period due to a pre-tax impairment loss of $16 million for the write down of fixed assets and patents at our waste coal recovery business in the first quarter of 2006.

Outlook We have agreed to sell a 50 percent interest in a portfolio of select Power and Industrial Projects. Immediately prior to the sale of the equity interest, the company that will own the portfolio of projects will obtain debt financing and the proceeds will be distributed to us. The total gross proceeds we will receive are expected to be approximately $800 million. The sale is subject to normal closing conditions and the receipt of satisfactory financing arrangements. The transaction is expected to close in the second half of 2007. We plan to account for our 50 percent ownership interest in the company that will own the portfolio of projects using the equity method. See Note 4 of the Notes to Consolidated Financial Statements.

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 these businesses, a partial or full tax credit phase-out is not expected to have a material adverse impact on our investment in Power and Industrial Projects.

Energy Trading

Our Energy Trading segment 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.

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Factors impacting income: Energy Trading s net loss decreased by $10 million during the second quarter of 2007. Energy Trading incurred a net loss of $12 million in the 2007 six-month period as compared to net income of $5 million in the comparable 2006 period. Favorability in the second quarter of 2007 is primarily attributable to a lower of cost or market adjustment on gas held in inventory in the second quarter of 2006, which did not recur in 2007. The decrease in net income for the 2007 six month period is due to the reversal of negative timing differences favorably impacting the first six months of 2006 as well as mark-to-market losses recorded in 2007.

	Three Months Ended June 30		Six Months Ended June 30	
(in Millions)	**2007**	2006	**2007**	2006
Operating Revenues	**$ 212**	$ 133	**$ 424**	$ 378
Fuel, Purchased Power and Gas	**203**	153	**396**	338
Gross Margin	**9**	(20)	**28**	40
Operation and Maintenance	**11**	13	**24**	26
Depreciation and Amortization	**1**	1	**2**	2
Taxes Other Than Income	**1**	1	**1**	1
Operating Income (Loss)	**(4)**	(35)	**1**	11
Other (Income) and Deductions	**16**	1	**19**	3
Income Tax Provision (Benefit)	**(7)**	(13)	**(6)**	3
Net Income (Loss)	**$ (13)**	$ (23)	**$ (12)**	$ 5

Gross margin increased by $29 million during the 2007 second quarter and decreased by $12 million in the 2007 six-month period. The increase in the second quarter of 2007 is due to higher realized gas and power activity. Realized favorability is primarily attributable to the unfavorable lower of cost or market adjustment, pertaining to gas held in inventory, recorded in the second quarter of 2006. Favorability for the second quarter of approximately $60 million is partially offset by approximately $30 million of mark-to-market losses reflecting the impact of liquidity threshold changes for natural gas contracts recorded in the second quarter of 2007. We updated our views on market liquidity based on observable market activity and market data gathered from recent monetization transactions. The decrease in the 2007 six-month period is impacted by the aforementioned mark-to-market losses on natural gas contracts compared to marked to market gains in 2006. This mark to market unfavorability is partially offset by the absence of the lower of cost or market adjustment in 2006.

Other (income) and deductions increased by $15 million and $16 million in the 2007 second quarter and six-month period, respectively. The increases are due to mark-to-market losses on foreign currency swaps that economically hedge exposure on anticipated power sales and existing transportation positions that settle in Canadian dollars. Underlying power swaps are marked-to-market and included in operating revenues while the transportation positions are not marked-to-market.

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, power transmission and full requirements contracts. The financial instruments are deemed derivatives, whereas the owned gas inventory, pipelines, transmission contracts, certain full requirements contracts 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 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.

See Fair Value of Contracts section that follows.

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Synthetic Fuel

Our Synthetic Fuel segment 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: Net income was higher by $71 million in the 2007 second quarter and $88 million higher in the 2007 six-month period due primarily to adjustments to reserves, lower depreciation and amortization expense, and one-time impairment charges in 2006, partially offset by lower gains associated with hedges. Synfuel production occurred throughout the 2007 periods as compared to 2006 when production was idled at all nine of our synfuel facilities beginning in May 2006.

	Three Months Ended June 30		Six Months Ended June 30	
(in Millions)	**2007**	2006	**2007**	2006
Operating Revenues	**$ 262**	$ 189	**$ 529**	$ 463
Operation and Maintenance	**314**	223	**638**	553
Depreciation and Amortization	**2**	9	**3**	22
Taxes other than Income	**4**	2	**8**	7
Other Asset (Gains) and Losses, Reserves and Impairments, Net	**(41)**	123	**(77)**	102
Operating Income (Loss)	**(17)**	(168)	**(43)**	(221)
Other (Income) and Deductions	**(2)**	(7)	**(6)**	(13)
Minority Interest	**(56)**	(109)	**(115)**	(180)
Income Taxes				
Provision (Benefit)	**14**	(18)	**27**	(10)
Production Tax Credits	**(10)**		**(24)**	(5)
	4	(18)	**3**	(15)
Net Income (Loss)	**$ 37**	$ (34)	**$ 75**	$ (13)

Operating revenues increased $73 million in the second quarter of 2007 and increased $66 million in the 2007 six-month period. Revenues were up in the 2007 periods due to production throughout 2007 as compared to 2006 when production was idled at all nine of our synfuel facilities beginning in May 2006.

Operation and maintenance expense increased $91 million in the second quarter of 2007 and increased $85 million in the 2007 six-month period. Expenses increased consistent with the revenue increases noted above due to the production throughout 2007 as compared to 2006 when production was idled at all nine of our synfuel facilities.

Depreciation and amortization expense decreased $7 million in the 2007 second quarter and decreased $19 million in the 2007 six-month period. Depreciation was lower as a result of lower asset carrying values due the impairment of fixed assets at all nine synfuel projects in the second quarter of 2006.

Other asset (gains) and losses, reserves and impairments, net increased $164 million in the second quarter of 2007 and increased $179 million in the 2007 six-month period. Gains were up primarily reflecting the annual partner payment adjustment, recognition of certain fixed gains that were reserved during the comparable 2006 period, higher hedge gains and the impact of one-time impairment charges and fixed note reserves recorded in 2006. The following table displays the various pre-tax components that comprise the determination of synfuel gains and losses in the three and six month periods in 2007 and 2006.

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	Three Months Ended June 30		Six Months Ended June 30	
(in Millions)	**2007**	2006	**2007**	2006
Components of Synfuel (Gains) Losses, Reserves and Impairments, Net				
(Gains) recognized associated with fixed payments	**$ (25)**	$ (8)	**$ (58)**	$ (30)
(Gains) recognized associated with variable payments	**(26)**	(17)	**(32)**	(9)
Reserves (reversed) recorded for contractual partners obligations	**(4)**	85	**(10)**	125
Other reserves and impairments	**(10)**	123	**3**	123
Hedge (gains) losses (mark-to-market)				
Hedges for 2006 exposure		(48)		(86)
Hedges for 2007 exposure	**24**	(12)	**20**	(21)
	$ (41)	$ 123	**$ (77)**	$ 102

Minority interest decreased $53 million in the second quarter of 2007 and decreased $65 million in the 2007 six-month period. The amounts reflect our partners share of operating losses associated with synfuel operations. The decrease primarily reflects the decrease in 2007 losses due to the 2006 one-time impairment charges.

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 increased $531 million in the 2007 second quarter and $514 million in the 2007 six-month period due primarily to the gain on the sale of the Antrim shale gas exploration and production business of approximately $897 million ($569 million after-tax). Partially offsetting the increases are adjustments to normalize the effective income tax rate. The income tax provisions of the segments are determined on a stand-alone basis. Corporate & Other records necessary adjustments so that the consolidated income tax expense during the quarter reflects the estimated calendar year effective rate.

DISCONTINUED OPERATIONS

DTE Georgetown (Georgetown) In the fourth quarter of 2006, management approved the marketing of Georgetown, an 80 MW natural gas-fired peaking electric generating plant, 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. In February 2007, we entered into an agreement to sell this plant. The sale received regulatory approval and closed in July 2007, resulting in gross proceeds of approximately $23 million, which approximated our carrying value. Georgetown did not have significant business activity for the three and six months ended June 30, 2007 and 2006.

DTE Energy Technologies (Dtech) - Dtech 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. Dtech did not have significant business activity for the three and six months ended June 30, 2007 and 2006.

See Note 4 of the Notes to Consolidated Financial Statements.

CUMULATIVE EFFECT OF ACCOUNTING CHANGES

Effective January 1, 2007, we adopted FIN 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109*. The cumulative effect of the adoption of FIN 48 represented a $5 million reduction to the January 1, 2007 balance of retained earnings.

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.

See Note 1 of the Notes to Consolidated Financial Statements.

CAPITAL RESOURCES AND LIQUIDITY

Cash Requirements

During the first six months of 2007, our cash requirements were met primarily through operations and short-term borrowings. We believe that we will have sufficient internal and external capital resources to fund anticipated capital and operating requirements.

On June 29, 2007, we sold our Antrim shale gas exploration and production business for gross proceeds of $1.258 billion.

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(in Millions)	Six Months Ended June 30 2007	2006
Cash and Cash Equivalents		
Cash Flow From (Used For):		
Operating activities:		
Net income	**$ 519**	$ 103
Depreciation, depletion and amortization	**467**	446
Deferred income taxes	**(4)**	53
Gain on sale of non-utility business	**(897)**	
Gain on sale of synfuel and other assets, net	**(67)**	(18)
Working capital and other	**980**	330
	998	914
Investing activities:		
Plant and equipment expenditures utility	**(480)**	(574)
Plant and equipment expenditures non-utility	**(141)**	(144)
Acquisitions, net of cash acquired		(27)
Proceeds from sale of non-utility business	**1,258**	
Proceeds from sale of synfuel and other assets, net	**216**	197
Restricted cash and other investments	**(42)**	(55)
	811	(603)
Financing activities:		
Issuance of long-term debt		545
Redemption of long-term debt	**(111)**	(620)
Short-term borrowings, net	**(330)**	(50)
Repurchase of common stock	**(333)**	(10)
Dividends on common stock and other	**(189)**	(188)
	(963)	(323)
Net Increase (Decrease) in Cash and Cash Equivalents	**$ 846**	$ (12)

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 approximately $900 million of cash during 2007-2009. Cash from operations totaling $998 million in the 2007 six-month period was up $84 million from the comparable 2006 period. The operating cash flow comparison reflects working capital and other improvements, primarily driven by risk management and trading activities, partially offset by the decrease in net income after adjusting for non-cash items (depreciation, depletion and amortization and deferred taxes) and gains on sales of businesses and assets.

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 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 under-recoveries 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, asset sales, proceeds from option hedges, and approximately $500 million of tax credit carry-forward 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.

Pursuant to our strategy to monetize value from our non-utility businesses, we have agreed to sell a 50 percent interest in a portfolio of select Power and Industrial Projects. Immediately prior to the sale of the equity interest, the company that will own the portfolio of projects will obtain debt financing and the proceeds will be distributed to us. The total gross proceeds we will receive are expected to be approximately $800 million. The sale is subject to normal closing conditions and the receipt of satisfactory financing arrangements. The transaction is expected to close in the second half of 2007. We plan to account for our 50 percent ownership interest in the company that will own the portfolio of projects using the equity method. See Note 4 to the Notes to Consolidated Financial Statements.

Investing Activities

Net cash from investing activities increased $1.4 billion in the 2007 six-month period as compared to the same 2006 period. The 2007 change was primarily related to the sale of our Antrim shale gas exploration and production business.

Financing Activities

Net cash used for financing activities increased $640 million in the 2007 six-month period, compared to the same 2006 period, primarily related to repurchase of common stock and lower short-term borrowings.

Cash Utilization

We expect cash generated from our utilities, our synfuels operations and the actual and potential cash from monetization of certain of our non-utility assets and operations to be used 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 monetization be accretive to earnings per share.

In conjunction with the signing of the agreement to sell Antrim, our Board of Directors authorized an increase in our common share repurchase program to $1.55 billion from $700 million. Our goal is to execute share repurchases of approximately $900 million by December 31, 2007, inclusive of purchases from the fourth quarter of 2006 through June 30, 2007 amounting to over $400 million. The amount of stock repurchased depends primarily on the net after-tax proceeds realized from the non-utility monetization plan. We plan to pursue open-market purchases throughout the year and we may also pursue an accelerated share repurchase plan should the right market conditions align with the expected completion of the non-utility restructuring plan.

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.

The accounting standards 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, in the Consolidated Statement of Operations, to reflect any change in the fair value of the contract, a practice known as mark-to-market (MTM) accounting. Changes in the fair value of a designated derivative that is highly effective as a cash flow hedge are recorded as a component of accumulated other comprehensive income, net of taxes, until the hedged item affects income. These amounts are subsequently reclassified into earnings as a component of the value of the forecasted transaction, in the same period as the forecasted transaction affects earnings. The ineffective portion of the fair value changes is recognized in the Consolidated Statement of Operations immediately.

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, 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 the financial statements.

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 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 Barnett gas reserves has been mitigated through 2010. 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.

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Roll-Forward of Mark-to-Market Energy Contract Net Assets

The following table provides details on changes in our MTM net asset or (liability) position during the six months ended June 30, 2007:

(in Millions)	Trading Activities: Proprietary Trading	Trading Activities: Structured Contracts	Trading Activities: Economic Hedges	Total	Other Non-Trading Activities	Total
MTM at December 31, 2006	$ (9)	$ (2)	$ (36)	$ (47)	$ (24)	$ (71)
Reclassed to realized upon settlement	1	(9)	39	31	17	48
Changes in fair value recorded to income	32	(64)	3	(29)	(241)	(270)
Amortization of option premiums	(7)	(1)		(8)		(8)
Amounts recorded to unrealized income	26	(74)	42	(6)	(224)	(230)
Amounts recorded in Other Comprehensive Income					(2)	(2)
Transfer of contracts between Trading and Non-Trading Activities		(323)		(323)	323	
Option premiums paid and other	(9)			(9)	5	(4)
MTM at June 30, 2007	$ 8	$ (399)	$ 6	$ (385)	$ 78	$ (307)

A substantial portion of the company s price risk related to its Antrim shale gas exploration and production business had been mitigated by financial contracts that hedged our price risk exposure through 2013. These financial contracts were accounted for as cash flow hedges, with changes in estimated fair value of the contracts for the liquid forward period reflected in other comprehensive income. Upon the sale of Antrim, the financial contracts no longer qualified as cash flow hedges. The contracts were retained and assigned to Energy Trading, and offsetting financial contracts were put into place to effectively settle these positions.

The following table provides a current and noncurrent analysis of Assets and Liabilities from risk management and trading activities, as reflected in the Consolidated Statement of Financial Position as of June 30, 2007. 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	Eliminations	Totals	Other Non-Trading Activities	Total Assets (Liabilities)
Current assets	$ 64	$ 102	$ 44	$ (29)	$ 181	$ 92	$ 273
Noncurrent assets	2	25	69	(2)	94		94
Total MTM assets	66	127	113	(31)	275	92	367

Current liabilities		(57)		(186)		(38)		29		(252)		(11)		(263)
Noncurrent liabilities		(1)		(340)		(69)		2		(408)		(3)		(411)
Total MTM liabilities		(58)		(526)		(107)		31		(660)		(14)		(674)
Total MTM net assets (liabilities)	$	8	$	(399)	$	6	$		$	(385)	$	78	$	(307)

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Maturity of Fair Value of MTM Energy Contract Net Assets

Our intent is to recognize MTM activity only when pricing data is obtained from active quotes and published indexes. We derive the pricing for our contracts from active quotes or external resources. Actively quoted indexes include exchange-traded positions such as the New York Mercantile Exchange and the Intercontinental Exchange, and over-the-counter positions for which broker quotes are available. Our intent is to recognize MTM activity only when pricing data is obtained from active quotes and published indexes. We periodically review our policy for changes in market liquidity. During 2007, we performed an analysis of the energy markets and its participants, including an evaluation of liquidity. We concluded these now meet our criteria and an extension of the liquid timeframe for recognizing mark-to-market activity for natural gas is warranted. Accordingly, our natural gas contracts are marked through 2014. As of this analysis, we continue to mark-to-market our power positions 24 months into the future. The majority of our long-dated power contracts relate to retail or structured transactions, which require the use of internal models to estimate fair value. The Company periodically assesses the liquid trading timeframe and other assumptions which may impact the estimated fair value derived from these models. We fully reserve all unrealized gains and losses related to periods beyond the liquid trading timeframe, therefore these unrealized gains and losses do not impact income.

As a result of adherence to generally accepted accounting principles, the tables above do not include the expected earnings impacts of certain non-derivative gas storage and power contracts. Consequently, gains and losses from these positions may not match with the related physical and financial hedging instruments in some reporting periods, resulting in volatility in DTE Energy s reported period-by-period earnings; however, the financial impact of this timing difference will reverse at the time of physical delivery and/or settlement. 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	$ 8	$	$	$	$ 8
Structured Contracts	(40)	(88)	(80)	(191)	(399)
Economic Hedges	11	3	(7)	(1)	6
Total Energy Trading Activities	(21)	(85)	(87)	(192)	(385)
Other Non-Trading Activities	82	(1)	(2)	(1)	78
Total	$ 61	$ (86)	$ (89)	$ (193)	$ (307)

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price 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 and a tracking mechanism to mitigate some losses from customer migration due to electric Customer Choice programs. See Note 6 of the Notes to Consolidated Financial Statements.

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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 production tax credits may be subject to changes in federal tax law. 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. To limit our exposure to the other commodities we may 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 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 June 30, 2007:

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(in Millions)	Credit Exposure before Cash Collateral	Cash Collateral	Net Credit Exposure
Investment Grade (1)			
A- and Greater	$ 397	$ (12)	$ 385
BBB+ and BBB	158		158
BBB-	72		72
Total Investment Grade	627	(12)	615
Non-investment grade (2)	49	(5)	44
Internally Rated investment grade (3)	96		96
Internally Rated non-investment grade (4)	22	(9)	13
Total	$ 794	$ (26)	$ 768

(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 21 percent 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 5 percent 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 6 percent 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 3 percent 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 June 30, 2007, the Company had a floating rate debt to total debt ratio of approximately 14.3 percent (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 and transmission capacity. To limit our exposure to foreign currency fluctuations, we have entered into a series of currency forward contracts through January 2012. 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 June 30, 2007 by a hypothetical 10 percent and calculating the resulting change in the fair values.

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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	$ (17)	$ 17	Commodity contracts
Power Contracts	$ (19)	$ 18	Commodity contracts
Oil Contracts	$ 115	$ (69)	Commodity options
Interest Rate Risk	$ (305)	$ 330	Long-term debt
Foreign Currency Risk	$ 2	$ (2)	Forward contracts

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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 the Company 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 the Securities Exchange Act of 1934 (Exchange Act) Rules 13a-15(e) and 15d-15(e)) as of June 30, 2007, 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 met.

(b) Changes in internal control over financial reporting

In April 2007, we began implementing the second phase of our Enterprise Business Systems (EBS) project. EBS is 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. Changes were made, and will be made, to many aspects of our internal control over financial reporting to adapt to EBS, and we are taking the necessary precautions to ensure that the transition to EBS will not have a material negative impact on our internal control over financial reporting. However, testing of the effectiveness of these controls will not be completed until the second half of 2007 and, therefore, we can provide no assurance that internal control issues will not arise.

There have been no other changes in the Company s internal control over financial reporting during the quarter ended June 30, 2007 that has materially affected, or is reasonably likely to materially affect, the Company s internal control over financial reporting.

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DTE Energy Company
Consolidated Statement of Operations (unaudited)

(in Millions, Except per Share Amounts)	Three Months Ended June 30 2007	Three Months Ended June 30 2006	Six Months Ended June 30 2007	Six Months Ended June 30 2006
Operating Revenues	**$ 1,954**	$ 1,895	**$ 4,684**	$ 4,530
Operating Expenses				
Fuel, purchased power and gas	**698**	588	**1,833**	1,648
Operation and maintenance	**1,110**	906	**2,168**	1,927
Depreciation, depletion and amortization	**242**	221	**467**	446
Taxes other than income	**114**	83	**208**	175
Gain on sale of non-utility business (Note 4)	**(897)**		**(897)**	
Other asset (gains) and losses, reserves and impairments, net	**(32)**	127	**(58)**	122
	1,235	1,925	**3,721**	4,318
Operating Income (Loss)	**719**	(30)	**963**	212
Other (Income) and Deductions				
Interest expense	**134**	134	**271**	267
Interest income	**(11)**	(13)	**(21)**	(25)
Other income	**(6)**	(12)	**(24)**	(24)
Other expenses	**25**	10	**34**	20
	142	119	**260**	238
Income (Loss) Before Income Taxes and Minority Interest	**577**	(149)	**703**	(26)
Income Tax Provision (Benefit)	**247**	(8)	**297**	50
Minority Interest	**(55)**	(109)	**(113)**	(180)
Income (Loss) from Continuing Operations	**385**	(32)	**519**	104
Loss from Discontinued Operations, net of tax		(1)		(2)
Cumulative Effect of Accounting Change, net of tax				1
Net Income (Loss)	**$ 385**	$ (33)	**$ 519**	$ 103

Basic Earnings (Loss) per Common Share				
Income (loss) from continuing operations	**$ 2.21**	$ (.18)	**$ 2.96**	$ .58
Discontinued operations		(.01)		(.01)
Cumulative effect of accounting change				.01
Total	**$ 2.21**	$ (.19)	**$ 2.96**	$ .58
Diluted Earnings (Loss) per Common Share				
Income (loss) from continuing operations	**$ 2.20**	$ (.18)	**$ 2.95**	$ .58
Discontinued operations		(.01)		(.01)
Cumulative effect of accounting change				.01
Total	**$ 2.20**	$ (.19)	**$ 2.95**	$ .58
Weighted Average Common Shares Outstanding				
Basic	**174**	177	**175**	177
Diluted	**175**	177	**176**	178
Dividends Declared per Common Share	**$ .53**	$ .515	**$ 1.06**	$ 1.03

See Notes to Consolidated Financial Statements (Unaudited)

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DTE Energy Company
Consolidated Statement of Financial Position (unaudited)

(in Millions)	June 30 2007	December 31 2006
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 993**	$ 147
Restricted cash	**143**	146
Accounts receivable (less allowance for doubtful accounts of $179 and $170, respectively)		
Customer	**1,391**	1,427
Collateral held by others	**102**	68
Other	**205**	442
Accrued power and gas supply cost recovery revenue	**88**	117
Inventories		
Fuel and gas	**530**	562
Materials and supplies	**180**	153
Deferred income taxes	**283**	245
Assets from risk management and trading activities	**273**	461
Other	**148**	193
	4,336	3,961
Investments		
Nuclear decommissioning trust funds	**794**	740
Other	**520**	505
	1,314	1,245
Property		
Property, plant and equipment	**19,024**	19,224
Less accumulated depreciation and depletion	**(7,564)**	(7,773)
	11,460	11,451
Other Assets		
Goodwill	**2,043**	2,057
Regulatory assets	**3,112**	3,226
Securitized regulatory assets	**1,182**	1,235
Intangible assets	**72**	72
Notes receivable	**149**	164
Assets from risk management and trading activities	**94**	164
Prepaid pension assets	**75**	71

Other	**121**		139
	6,848		7,128
Total Assets	**$ 23,958**	$	23,785

See Notes to Consolidated Financial Statements (Unaudited)

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DTE Energy Company
Consolidated Statement of Financial Position (unaudited)

(in Millions, Except Shares)	June 30 2007	December 31 2006
LIABILITIES AND SHAREHOLDERS EQUITY		
Current Liabilities		
Accounts payable	**$ 1,344**	$ 1,145
Accrued interest	**116**	115
Dividends payable	**91**	94
Short-term borrowings	**801**	1,131
Gas inventory equalization	**145**	
Current portion of long-term debt, including capital leases	**403**	354
Liabilities from risk management and trading activities	**263**	437
Deferred gains from asset sales	**288**	208
Other	**701**	680
	4,152	4,164
Long-Term Debt (net of current portion)		
Mortgage bonds, notes and other	**5,816**	5,918
Securitization bonds	**1,124**	1,185
Trust preferred-linked securities	**289**	289
Capital lease obligations	**75**	82
	7,304	7,474
Other Liabilities		
Deferred income taxes	**1,562**	1,465
Regulatory liabilities	**808**	765
Asset retirement obligations	**1,248**	1,221
Unamortized investment tax credit	**113**	120
Liabilities from risk management and trading activities	**411**	259
Liabilities from transportation and storage contracts	**137**	157
Accrued pension liability	**393**	388
Accrued postretirement liability	**1,424**	1,414
Deferred gains from asset sales	**16**	36
Nuclear decommissioning	**126**	119
Other	**328**	312
	6,566	6,256

Commitments and Contingencies (Notes 2, 6 and 9)

Minority Interest	**47**	42
Shareholders Equity		
Common stock, without par value, 400,000,000 shares authorized, 170,649,715 and 177,138,060 shares issued and outstanding, respectively	**3,311**	3,467
Retained earnings (less FIN 48 cumulative effect adjustment of $5 in 2007)	**2,700**	2,593
Accumulated other comprehensive loss	**(122)**	(211)
	5,889	5,849
Total Liabilities and Shareholders Equity	**$ 23,958**	$ 23,785

See Notes to Consolidated Financial Statements (Unaudited)

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DTE Energy Company
Consolidated Statement of Cash Flows (Unaudited)

(in Millions)	Six Months Ended June 30 2007	2006
Operating Activities		
Net Income	**$ 519**	$ 103
Adjustments to reconcile net income to net cash from operating activities:		
Depreciation, depletion and amortization	**467**	446
Deferred income taxes	**(4)**	53
Gain on sale of interests in synfuel projects	**(77)**	(20)
Gain on sale of non-utility business	**(897)**	
Other asset (gains), losses and reserves, net	**10**	2
Impairment of synfuel projects		122
Partners share of synfuel project losses	**(115)**	(180)
Contributions from synfuel partners	**101**	129
Cumulative effect of accounting change		(1)
Changes in assets and liabilities, exclusive of changes shown separately	**994**	260
Net cash from operating activities	**998**	914
Investing Activities		
Plant and equipment expenditures utility	**(480)**	(574)
Plant and equipment expenditures non-utility	**(141)**	(144)
Acquisitions, net of cash acquired		(27)
Proceeds from sale of interests in synfuel projects	**221**	163
Refunds to synfuel partners	**(16)**	
Proceeds from sale of non-utility business	**1,258**	
Proceeds from sale of other assets, net	**11**	34
Restricted cash for debt redemptions	**4**	(5)
Proceeds from sale of nuclear decommissioning trust fund assets	**124**	99
Investment in nuclear decommissioning trust funds	**(140)**	(118)
Other investments	**(30)**	(31)
Net cash from (used for) investing activities	**811**	(603)
Financing Activities		
Issuance of long-term debt		545
Redemption of long-term debt	**(111)**	(620)
Short-term borrowings, net	**(330)**	(50)
Repurchase of common stock	**(333)**	(10)
Dividends on common stock	**(187)**	(182)
Other	**(2)**	(6)
Net cash used for financing activities	**(963)**	(323)

Net Increase (Decrease) in Cash and Cash Equivalents	**846**	(12)
Cash and Cash Equivalents at Beginning of the Period	**147**	88
Cash and Cash Equivalents at End of the Period	**$ 993**	$ 76

See Notes to Consolidated Financial Statements (Unaudited)

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DTE Energy Company
Consolidated Statement of Changes in Shareholders Equity
and Comprehensive Income (unaudited)

(Dollars in Millions, Shares in Thousands)	Common Stock Shares	Common Stock Amount	Retained Earnings	Accumulated Other Comprehensive Loss	Total
Balance, December 31, 2006	177,138	$ 3,467	$ 2,593	$ (211)	$ 5,849
Net income			519		519
Implementation of FIN 48			(5)		(5)
Pension and postretirement obligations, net of tax				2	2
Dividends declared on common stock			(185)		(185)
Repurchase and retirement of common stock	(6,648)	(153)	(222)		(375)
Net change in unrealized gains on derivatives, net of tax				88	88
Net change in unrealized losses on investments, net of tax				(1)	(1)
Stock-based compensation	160	(3)			(3)
Balance, June 30, 2007	**170,650**	**$ 3,311**	**$ 2,700**	**$ (122)**	**$ 5,889**

The following table displays comprehensive income for the six-month periods ended June 30:

(in Millions)	**2007**	2006
Net income	**$ 519**	$ 103
Other comprehensive income (loss), net of tax:		
Pension and postretirement obligations, net of taxes of $1 and $- , respectively	**2**	
Net unrealized gains (losses) on derivatives:		
Gains (losses) arising during the period, net of taxes of $(77) and $46, respectively	**(143)**	86
Amounts reclassified to income, net of taxes of $125 and $(24), respectively	**231**	(44)
	88	42
Net unrealized gains (losses) on investments:		
Losses arising during the period, net of taxes of $(2) and $(1), respectively	**(3)**	(2)
Amounts reclassified from income, net of taxes of $1 and $-, respectively	**2**	
	(1)	(2)
Comprehensive income	**$ 608**	$ 143

See Notes to Consolidated Financial Statements (Unaudited)

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DTE Energy Company
Notes to Consolidated Financial Statements (Unaudited)

NOTE 1 GENERAL

These Consolidated Financial Statements should be read in conjunction with the Notes to Consolidated Financial Statements included in the 2006 Annual Report on Form 10-K.

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.

The Consolidated Financial Statements are unaudited, but in our opinion include all adjustments necessary for a fair presentation of such financial statements. All adjustments are of a normal recurring nature, except as otherwise disclosed in these Consolidated Financial Statements and Notes to Consolidated Financial Statements. Financial results for this interim period are not necessarily indicative of results that may be expected for any other interim period or for the fiscal year ending December 31, 2007.

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

Asset Retirement Obligations

We have a legal retirement obligation for the decommissioning costs of 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. We recognize such obligations as liabilities at fair market value at the time the associated assets are placed in service. Fair value is measured using expected future cash outflows discounted at our credit-adjusted risk-free rate.

For our regulated operations, timing differences arise in the expense 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*.

A reconciliation of the asset retirement obligations for the 2007 six-month period follows:

(in Millions)	
Asset retirement obligations at January 1, 2007	$ 1,221
Accretion	40
Liabilities incurred	1
Liabilities settled	(17)
Revision in estimated cash flows	3
Asset retirement obligations at June 30, 2007	$ 1,248

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.

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Goodwill
Goodwill decreased $14 million during the six months ended June 30, 2007 primarily as a result of the goodwill associated with the Antrim shale gas exploration and production gas business which was sold in June 2007.

Intangible Assets
We have certain intangible assets relating to non-utility contracts and emission allowances. The gross carrying amount and accumulated amortization of intangible assets at June 30, 2007 was $82 million and $10 million, respectively. As of December 31, 2006 the gross carrying amount and accumulated amortization of intangible assets was $80 million and $8 million, respectively. Amortization expense amounted to $1.25 million for each of the three months ended June 30, 2007 and 2006 and $2.5 million for each of the six months ended June 30, 2007 and 2006. Amortization expense of intangible assets is estimated to be $6 million annually for 2007 through 2011.

Retirement Benefits and Trusteed Assets
The components of net periodic benefit costs for qualified and non-qualified pension benefits and other postretirement benefits follow:

(in Millions)	**Pension Benefits**		**Other Postretirement Benefits**	
Three Months Ended June 30	**2007**	2006	**2007**	2006
Service cost	**$ 15**	$ 16	**$ 15**	$ 16
Interest cost	**43**	44	**31**	28
Expected return on plan assets	**(60)**	(56)	**(16)**	(14)
Amortization of				
Net loss	**13**	15	**16**	17
Prior service cost	**1**	2		
Transition liability				1
Special termination benefits	**1**	15		1
Net periodic benefit cost	**$ 13**	$ 36	**$ 46**	$ 49
Six Months Ended June 30	**2007**	2006	**2007**	2006
Service cost	**$ 31**	$ 32	**$ 30**	$ 31
Interest cost	**88**	88	**61**	57
Expected return on plan assets	**(120)**	(111)	**(33)**	(29)
Amortization of				
Net loss	**28**	30	**33**	35
Prior service cost (credit)	**2**	4	**(1)**	(1)
Transition liability			**2**	3
Special termination benefits	**5**	15	**2**	1
Net periodic benefit cost	**$ 34**	$ 58	**$ 94**	$ 97

Special termination benefits in the above tables represent costs associated with our Performance Excellence Process.

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Income Taxes

Uncertain Tax Positions

We adopted the provisions of FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109 (FIN 48)* on January 1, 2007. This interpretation prescribes a recognition threshold and a measurement attribute for the financial statement reporting of tax positions taken or expected to be taken on a tax return. As a result of the implementation of FIN 48, we recognized a $5 million increase in liabilities which was accounted for as a reduction to the January 1, 2007 balance of retained earnings. The total amount of unrecognized tax benefits amounted to $41 million and $26 million at January 1, 2007 and June 30, 2007, respectively. The decline in unrecognized tax benefits during the six months ended June 30, 2007 was primarily attributable to settlements with the Internal Revenue Service (IRS) for the 2002 and 2003 tax years. Unrecognized tax benefits totaling $25 million at January 1, 2007 and $17 million at June 30, 2007, if recognized, would favorably impact our effective tax rate.

We recognize interest and penalties pertaining to income taxes in Interest expense and Other expenses, respectively, on our Consolidated Statement of Operations. Accrued interest pertaining to income taxes totaled $8 million and $7 million at January 1, 2007 and June 30, 2007, respectively. We had no accrued penalties pertaining to income taxes. We recognized interest expense in relation to income taxes of $0.2 million and $1.2 million during the three and six months ended June 30, 2007, respectively, compared to $0.3 million and $0.6 million during the three and six months ended June 30, 2006, respectively.

Our U.S. federal income tax returns for years 2004 and subsequent years remain subject to examination by the IRS. We also file tax returns in numerous state jurisdictions with varying statutes of limitation.

Michigan Business Tax

On July 12, 2007, the Michigan Business Tax (MBT) was enacted by the State of Michigan to replace the Michigan Single Business Tax (MSBT) effective January 1, 2008.

The MBT is comprised of the following:

- An apportioned modified gross receipts tax of 0.8 percent; and
- An apportioned business income tax of 4.95 percent.

The modified gross receipts base and business income base are apportioned to Michigan based on a single factor that is derived by dividing total revenue in Michigan by total revenue from all jurisdictions. The modified gross receipts tax base is defined as gross receipts less purchases from other firms before apportionment. The MBT will be accounted for as an income tax.

The MBT provides credits for Michigan business investment, compensation, and research and development. Effective with the enactment of the MBT in the third quarter of 2007, we will record deferred income taxes for cumulative temporary differences between book and taxable income. We have not yet determined the amount, but expect to record a significant net deferred tax liability for these MBT cumulative temporary differences. The effect of recognizing the MBT net deferred tax liability will result in an adjustment to third quarter 2007 income tax expense. We expect to recognize a regulatory asset at our regulated utilities for the cumulative MBT temporary differences at the date of enactment.

The MSBT is a value-added tax imposed on business income plus compensation paid, interest paid and depreciation. In addition, the MSBT allows for an investment tax credit. The MSBT tax rate is 1.9 percent. Since the MSBT is a value added tax rather than an income tax, we classified amounts associated

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with this tax on the Consolidated Statement of Operations under the caption, Taxes other than income. MSBT amounted to $29 million and $5 million for the three months ended June 30, 2007 and 2006, respectively, and amounted to $34 million and $10 million for the six months ended June 30, 2007 and 2006, respectively.

We are currently assessing the effects of the MBT and have not yet determined its impact on our consolidated financial statements.

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.

Stock-based compensation expense and associated tax benefits follow:

	Three Months Ended June 30		**Six Months Ended June 30**	
(in Millions)	**2007**	2006	**2007**	2006
Stock-based compensation expense	**$13**	$6	**$19**	$12
Tax benefit of compensation expense	**$ 5**	$2	**$ 7**	$ 4

Compensation cost capitalized in property, plant and equipment was $1 million and $0.4 million during the three months ended June 30, 2007 and 2006, respectively, while compensation cost capitalized in property, plant and equipment was $1.5 million and $1 million for the six months ended June 30, 2007 and 2006, respectively.

Effective January 1, 2006, we adopted SFAS 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 for the six months ended June 30, 2006 as a result of estimating forfeitures for previously granted stock awards and performance shares.

Stock Options

The following table summarizes our stock option activity for the six months ended June 30, 2007:

	Number of Options	Weighted Average Exercise Price
Outstanding at December 31, 2006	5,667,197	$ 41.60
Granted Granted	417,800	$ 47.75
Exercised Exercised	(1,472,234)	$ 41.44
Forfeited or Expired Canceled	(16,082)	$ 42.39
Outstanding at June 30, 2007	4,596,681	$ 42.20
Exercisable at June 30, 2007	3,490,322	$ 41.18

As of June 30, 2007, the weighted average remaining contractual life for the exercisable shares is 5.33 years. During the first six months of 2007, 870,383 options vested. As of June 30, 2007, 1,106,359 options were non-vested. Generally, our stock options vest over a three year period.

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

	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
Risk-free interest rate	**4.61**%	4.87%
Dividend yield	**4.40**%	4.99%
Expected volatility	**17.85**%	19.25%
Expected life	**6 years**	6 years

Stock Awards

The following table summarizes our stock awards activity for the six months ended June 30, 2007:

	Restricted Stock	Weighted Average Grant Date Fair Value
Balance at December 31, 2006	666,136	$ 43.20
Grants	265,300	$ 48.73
Forfeitures	(28,715)	$ 44.12
Vested	(203,084)	$ 40.95
Balance at June 30, 2007	699,637	$ 45.37

Performance Share Awards

The following table summarizes our performance share activity for the six months ended June 30, 2007:

	Performance Shares
Balance at December 31, 2006	1,035,696
Grants	489,765
Forfeitures	(48,730)
Payouts	(267,265)
Balance at June 30, 2007	1,209,466

Unearned Compensation Cost

As of June 30, 2007, there was $45 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 1.52 years.

Gas in Inventory

Gas inventory at MichCon is priced on a last-in, first-out (LIFO) basis. In anticipation that interim inventory reductions will be replaced prior to year end, the cost of gas of net withdrawals from inventory is recorded at the estimated average purchase rate for the calendar year. The excess of these charges over the weighted average cost of the LIFO pool is credited to the gas inventory equalization account. During interim periods when there are net injections to inventory, the equalization account is reversed.

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:

	Six Months Ended June 30	
(in Millions)	**2007**	2006
Changes in Assets and Liabilities, Exclusive of Changes Shown Separately		
Accounts receivable, net	**$ 241**	$ 644
Accrued GCR revenue	**(77)**	116
Inventories	**7**	(1)
Accrued/Prepaid pensions	**1**	57
Accounts payable	**131**	(162)
Accrued PSCR refund	**46**	(63)
Exchange gas payable	**(16)**	(32)
Income taxes payable	**136**	(39)
General taxes	**21**	(9)
Risk management and trading activities	**213**	(316)
Gas inventory equalization	**145**	52
Postretirement obligation	**10**	(9)
Other assets	**67**	(13)
Other liabilities	**69**	35
	$ 994	$ 260

Supplementary cash and non-cash information follows:

	Six Months Ended June 30	
(in Millions)	**2007**	2006
Cash Paid for		
Interest paid (excluding interest capitalized)	**$271**	$268
Income taxes paid, net of refunds	**$109**	$ 32
Noncash Financing Activities		
Repurchase of common stock	**$ 42**	

In conjunction with maintaining certain traded risk management positions, we may be required to post cash collateral with our clearing agent; therefore, we entered into a demand financing agreement for up to $150 million in lieu of posting additional cash collateral (a non-cash transaction). The amounts outstanding under this facility were $26 million and $23 million at June 30, 2007 and December 31, 2006, respectively.

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Other asset (gains) and losses, reserves and impairments, net

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

(in Millions)	Three Months Ended June 30		Six Months Ended June 30	
Description	**2007**	2006	**2007**	2006
Synfuel (Gains), Losses and Reserves, Net				
(Gains) recognized for fixed payments	$ **(25)**	$ (8)	$ **(58)**	$ (30)
(Gains) losses recognized for variable payments	**(26)**	(17)	**(32)**	(9)
Reserves (reversed) recorded for contractual partners obligations	**(4)**	85	**(10)**	125
Other reserves and impairments	**(10)**	123	**3**	123
Hedge (gains) (mark-to-market)	**24**	(60)	**20**	(107)
Synfuels , net	**(41)**	123	**(77)**	102
Other Non-utility impairments:				
Waste coal recovery				16
Barnett shale	**9**		**9**	
Electric utility	**(1)**		**6**	
Gas utility		3	**3**	3
Other	**1**	1	**1**	1
	$ **(32)**	$ 127	**$** **(58)**	$ 122

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 and are available through December 31, 2007. 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 June 30, 2007, we have generated and recorded approximately $605 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 2007, we estimate the threshold price at which the tax credit would begin to be reduced is $56 per barrel and would be completely phased out if the Reference Price reached $71 per barrel. As of June 30, 2007, the realized NYMEX daily closing price of a barrel of oil was approximately $66 for 2007, equating to an estimated Reference Price of $60, which we estimate to be within the phase-out range.

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

Through June 2007, we have sold interests in all of the synthetic fuel production plants, representing approximately 91 percent 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 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 until there is persuasive evidence that phase-out of some or all of the tax credits will not occur. This could result in shifting earnings from earlier quarters to later quarters this year.

The gain from the sale of synfuel facilities is comprised of fixed and variable components. The fixed component represents note payments, is not generally 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. During the three months ended June 30, 2007 and 2006, fixed gains recognized totaled $25 million and $8 million, respectively. During the six months ended June 30, 2007 and 2006, fixed gains recognized totaled $58 million and $30 million, respectively. During the three months ended June 30, 2007 and 2006, variable gains recognized totaled $26 million and $17 million, respectively. During the six months ended June 30, 2007 and 2006, variable gains recognized totaled $32 million and $9 million, respectively. Synfuel results recognized were impacted by adjustments to prior year gains and reserves to reflect issuance of the final Reference Prices by the IRS.

Contractual Partners Obligations

Our partners reimburse us (through the project entity) for the operating losses of the synfuel facilities. The reimbursements are referred to as capital contributions. In the event that the production 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 refunded $16 million to our partners in the first six months of 2007. Reserves established for an expected 2007 tax credit phase out, net of adjustments primarily resulting from the issuance of the final 2006 Reference Price by the IRS, had the effect of reducing the reserve balance by $4 million and $10 million in the three and six months ended June 30, 2007. This compares with increasing reserves by $85 million and $125 million in the three and six months ended June 30, 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 were a pre-tax loss of $24 million in the second quarter of 2007 compared to a pre-tax gain of $60 million during the second quarter of 2006, while such changes were a pre-tax loss of $20 million in the first six months of 2007 compared to a pre-tax gain of $107 million during the first six months of 2006. The fair value changes are recorded as adjustments to the gain from selling interests in synfuel facilities and are included in the Other asset gains and losses, reserves and impairments, net line item in the Consolidated Statement of Operations.

Impairments and Reserves

During the second quarter of 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. During the second quarter of 2006, we recorded a pre-tax loss of $123 million within the Other asset (gains) and losses, reserves and impairments, net, line item in the Consolidated Statement of Operations. The loss primarily consists of two components: $77 million for synfuel related fixed asset impairment and inventory write-down and $42 million for a reserve for notes receivable related to the sale of interests in synfuel facilities. 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 June 30, 2007 is $2.7 billion. At June 30, 2007, we have reserved $291 million of our maximum potential liability primarily representing the possible refund of certain payments made by our synfuel partners.

NOTE 3 NEW ACCOUNTING PRONOUNCEMENTS

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 are currently assessing the effects of this statement, and have not yet determined its impact on our consolidated financial statements.

In February 2007, the FASB issued SFAS No. 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 its impact on our 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 credits.

We adopted the requirement to recognize the funded status of a defined benefit pension or defined benefit other postretirement plan and the related disclosure requirements 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 have not yet determined which of the available transition measurement options we will use.

NOTE 4 DISPOSALS AND DISCONTINUED OPERATIONS

Sale of Antrim Shale Gas Exploration and Production Business

On June 29, 2007, we sold our Antrim shale gas exploration and production business (Antrim) to Atlas Energy Resources, LLC for gross proceeds of $1.258 billion. The pre-tax gain recognized on this sale amounted to $897 million ($569 million after-tax) and is reported on the Consolidated Statement of Operations for the three and six months ended June 30, 2007 under the line item, Gain on sale of non-utility business, and included in the Corporate & Other segment. Prior to the sale, the operating results of Antrim were reflected in the Unconventional Gas Production segment.

The Antrim business will not be presented as a discontinued operation due to continuation of cash flows related to the sale of a portion of Antrim s natural gas production to Energy Trading under the terms of natural gas sales contracts which expire in 2010 and 2012. These continuing cash flows, while not significant to DTE, are significant to Antrim and therefore meet the definition of continuing cash flows as described in EITF 03-13, *Applying the Conditions in Paragraph 42 of FASB Statement No. 144 in Determining Whether to Report Discontinued Operations*.

A substantial portion of the Company s price risk related to expected gas production from its Antrim shale business had been hedged through 2013. These financial contracts were accounted for as cash flow hedges, with changes in estimated fair value of the contracts for the liquid forward period reflected in other comprehensive income. Upon the sale of Antrim, the financial contracts no longer qualified as cash flow hedges. The contracts were retained and assigned to Energy Trading, and offsetting financial contracts were put into place to effectively settle these positions. As a result of these transactions and market research performed by the Company, DTE gained additional insight and visibility into the value ascribed to these contracts by third party market participants for the entire duration of the contracts. In

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conjunction with the Antrim sale and effective settlement of these contract positions, Antrim reclassified amounts held in accumulated other comprehensive income and recorded the effective settlements, reducing operating revenues in the second quarter of 2007 by $323 million.

DTE Georgetown (Georgetown)

Georgetown, is an 80 MW natural gas-fired peaking electric generating plant. 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. In February 2007, we entered into an agreement to sell this plant. The sale received regulatory approval and closed in July 2007 resulting in gross proceeds of approximately $23 million, which approximates our carrying value. As of June 30, 2007, Georgetown s assets are $23 million and its liabilities are $1 million. Georgetown did not have significant business activity for the three and six months ended June 30, 2007 and 2006.

DTE Energy Technologies (Dtech)

Dtech assembled, marketed, distributed and serviced distributed generation products, provided application engineering, and monitored and managed on-site generation system operations. In the third quarter of 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. The Dtech restructuring plan met the SFAS No. 144 criteria of an asset held for sale and we reported its operating results as a discontinued operation. We expect continued legal and warranty expenses in 2007 related to Dtech s operations prior to the third quarter of 2005. As of June 30, 2007, Dtech had liabilities of approximately $2.7 million. Dtech did not have significant business activity for the three and six months ended June 30, 2007 and 2006.

Agreement to Sell Interest in Certain Power and Industrial Projects

We have agreed to sell a 50 percent interest in a portfolio of select Power and Industrial Projects. Immediately prior to the sale of the equity interest, the company that will own the portfolio of projects will obtain debt financing and the proceeds will be distributed to us. The total gross proceeds we will receive are expected to be approximately $800 million. The sale is subject to normal closing conditions and the receipt of satisfactory financing arrangements. The transaction is expected to close in the second half of 2007. We plan to account for our 50 percent ownership interest in the company that will own the portfolio of projects using the equity method.

Crete

In July 2007, we entered into an agreement to sell our 50 percent interest in Crete, a 320 MW natural gas-fired peaking electric generating plant. The sale of the Crete interest is subject to receipt of regulatory approval and is expected to close in the second half of 2007.

NOTE 5 IMPAIRMENTS AND RESTRUCTURING

Impairments

Barnett shale

In the second quarter of 2007, our Unconventional Gas Production segment recorded a pre-tax impairment loss of $9 million related to the write-off of unproved properties in Bosque County, which is located in the southern expansion area of the Barnett shale basin in north Texas, and the write-off of costs associated with various leases expiring in the third quarter of 2007. The properties were impaired due to the lack of economic and operating viability of the project.

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The impairment loss was recorded within the Other asset (gains) and losses, reserves, and impairments, net line in the Consolidated Statement of Operations.

Waste Coal Recovery

During the first quarter of 2006, our Power and Industrial Projects segment recorded a pre-tax impairment loss of $16 million related to 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. The impairment loss was recorded within the Other asset (gains) and losses, reserves and impairments, net line in the Consolidated Statement of Operations.

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 to continue into 2008.

We have incurred CTA for employee severance and other costs. Other costs include project management and consultant support. Pursuant to MPSC authorization, beginning in the third quarter of 2006, Detroit Edison deferred approximately $102 million of CTA in 2006. Detroit Edison began amortizing deferred 2006 costs in 2007 as the recovery of these costs was provided for by the MPSC. Amortization expense amounted to $3 million and $5 million for the three and six months ended June 30, 2007, respectively. Detroit Edison deferred approximately $8 million and $21 million of CTA during the three and six months ended June 30, 2007, respectively. 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 assets line on the Consolidated Statement of Financial Position. Expenses incurred for the three months ended June 30, 2007 and 2006 are as follows:

	Employee Severance Costs		**Other Costs**		**Total Cost**	
(in Millions)	**2007**	2006	**2007**	2006	**2007**	2006
Costs incurred:						
Electric Utility	**$ 3**	$ 18	**$ 7**	$ 19	**$ 10**	$ 37
Gas Utility		2	**1**	1	**1**	3
Other	**1**				**1**	
Total costs	**4**	20	**8**	20	**12**	40
Less amounts deferred or capitalized:						
Electric Utility	**3**		**7**		**10**	
Amount expensed	**$ 1**	$ 20	**$ 1**	$ 20	**$ 2**	$ 40

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Expenses incurred for the six months ended June 30, 2007 and 2006 are as follows:

(in Millions)	Employee Severance Costs 2007	Employee Severance Costs 2006	Other Costs 2007	Other Costs 2006	Total Cost 2007	Total Cost 2006
Costs incurred:						
Electric Utility	**$ 11**	$ 18	**$ 14**	$ 31	**$ 25**	$ 49
Gas Utility	**2**	2	**1**	4	**3**	6
Other	**1**			1	**1**	1
Total costs	**14**	20	**15**	36	**29**	56
Less amounts deferred or capitalized:						
Electric Utility	**11**		**14**		**25**	
Amount expensed	**$ 3**	$ 20	**$ 1**	$ 36	**$ 4**	$ 56

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.

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. Detroit Edison filed its response explaining why its electric rates should not be reduced in 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 April 13, 2008, one year from the filing of the general rate case on April 13, 2007, rates were reduced by an additional $26 million, for a total reduction of $79 million annually. 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 provided 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 percent 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 percent of the increase in non-fuel revenue to the unrecovered regulatory asset balance. Approximately $20 million and $23 million were credited to the unrecovered regulatory asset balance in the three and six months ended June 30, 2007, respectively.

2007 Electric Rate Case Filing

Pursuant to the February 2006 MPSC order in Detroit Edison s rate restructuring case and the August 2006 MPSC order in the settlement of the show cause case, Detroit Edison filed a general rate case on April 13, 2007 based on a 2006 historical test year. The filing with the MPSC requests a $123 million, or 2.9 percent, average increase in Detroit Edison s annual revenue requirement for 2008.

The requested $123 million increase in revenues is required in order to recover significant environmental compliance costs and inflationary increases, partially offset by net savings associated with the Performance Excellence Process. The filing is based on a return on equity of 11.25 percent on an expected 50 percent equity capital and 50 percent debt capital structure by year-end 2008.

In addition, Detroit Edison s filing makes, among other requests, the following proposals:

- Make progress toward correcting the existing rate structure to more accurately reflect the actual cost of providing service to customers.
- Equalize distribution rates between Detroit Edison full service and electric Customer Choice customers.
- Re-establish with modification the Choice Incentive Mechanism (CIM) originally established in the Detroit Edison 2006 show cause filing. The CIM reconciles changes related to customers moving between Detroit Edison full service and electric Customer Choice.
- Terminate the Pension Equalization Mechanism.
- Establish an emission allowance pre-purchase plan to ensure that adequate emission allowances will be available for environmental compliance.
- Establish a methodology for recovery of the costs associated with preparation of an application for a new nuclear generation facility.

Also, in the filing, in conjunction with Michigan s 21st Century Energy Plan, Detroit Edison has reinstated a long-term integrated resource planning (IRP) process with the purpose of developing the least overall cost plan to serve customers generation needs over the next 20 years. Based on the IRP, new base load capacity may be required for Detroit Edison. To protect tax credits available under Federal law, Detroit Edison determined it would be prudent to initiate the application process for a new nuclear unit. Detroit Edison has not made a final decision to build a new nuclear unit. Detroit Edison is preserving its option to build at some point in the future by beginning the complex nuclear licensing process in 2007. Also, beginning the licensing process at the present time, positions Detroit Edison potentially to take advantage of tax incentives of up to $320 million derived from provisions in the 2005 Energy Policy Act that will benefit customers. To qualify for these substantial tax credits, a combined operating license for construction and operation of an advanced nuclear generating plant must be docketed by the Nuclear Regulatory Commission no later than December 31, 2008. Preparation and approval of a combined operating license can take up to 4 years and is estimated to cost at least $60 million.

Detroit Edison will likely submit a supplement to its April 2007 rate case filing to account for certain recent events. A July 2007 decision by the Court of Appeals of the State of Michigan reverses the November 2004 MPSC order in a prior Detroit Edison rate case that denied recovery of merger control premium costs. Also, the Michigan legislature recently enacted the Michigan Business Tax effective in 2008. A supplemental filing would assess the impacts of these events and their effect on Detroit Edison s requested revenue increase.

An MPSC order related to this filing is expected in 2008.

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 the Performance Excellence Process to continue into 2008. Detroit Edison s CTA is estimated to total approximately $150 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. At year-end 2006, Detroit Edison recorded deferred CTA costs of $102 million as a regulatory asset and began amortizing deferred 2006 costs in 2007, as the recovery of these costs was provided for by the MPSC in its order approving the settlement of the show cause proceeding. During the three and six months ended June 30, 2007, Detroit Edison deferred CTA costs of $8 million and $21 million, respectively. Amortization of prior year deferred CTA costs amounted to $3 million and $5 million during the three and six months ended June 30, 2007, respectively. MichCon cannot defer CTA costs at this time because a recovery mechanism has not been established.

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 June 30, 2007, approximately $22 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.

Fermi 2 Enhanced Security Costs Settlement

The Customer Choice and Electricity Reliability Act, as amended in 2003, allows for the recovery of reasonable and prudent costs of new and enhanced security measures required by state or federal law, including providing for reasonable security from an act of terrorism. In December 2006, Detroit Edison filed an application with the MPSC for recovery of $11.4 million of Fermi 2 Enhanced Security Costs (ESC), discounted back to September 11, 2001 plus carrying costs from that date. In April 2007, the MPSC approved a settlement agreement that authorizes Detroit Edison to recover Fermi-2 ESC incurred during the period September 11, 2001 through December 31, 2005. The settlement defined Detroit Edison s ESC, discounted back to September 11, 2001, as $9.1 million, plus carrying charges. A total of $12 million, including carrying charges, has been recorded as a regulatory asset at June 30, 2007. Detroit Edison is authorized to incorporate into its rates an enhanced security factor over a period not to exceed five years.

Reconciliation of Regulatory Asset Recovery Surcharge

In December 2006, Detroit Edison filed a reconciliation of costs underlying its existing Regulatory Asset Recovery Surcharge (RARS). In this filing, Detroit Edison replaced estimated costs for 2003 2005 included in the last general rate case with actual costs incurred. Also reflected in the filing was the replacement of estimated revenues with actual revenues collected. This true-up filing was made to maximize the remaining time for recovery of significant cost increases prior to expiration of the RARS five-year recovery limit under PA 141. Detroit Edison s filing indicated a $53 million deficiency for RARS-related costs from the level originally established. Detroit Edison seeks reconciliation of the regulatory asset surcharge to ensure proper recovery by the end of the five year period of: (1) Clean Air Act Expenditures, (2) Capital in Excess of Base Depreciation, (3) MISO Costs and (4) the regulatory liability for the 1997 Storm Charge. Detroit Edison subsequently adjusted its estimated deficiency to $49 million. In July 2007, the MPSC approved a negotiated settlement for Detroit Edison that resulted in a $5 million write down of RARS-related costs in the quarter ended June 30, 2007.

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. Included in the factor were power supply costs, transmission expenses and nitrogen oxide (NOx) emission allowance costs. In September 2005, the MPSC approved Detroit Edison s 2005 PSCR plan case. At December 31, 2005, Detroit Edison 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. In September 2006, the MPSC ordered the Company to roll the entire 2004 PSCR over-collection amount to the Company s 2005 PSCR Reconciliation. An order was issued on May 22, 2007 approving a 2005 PSCR undercollection amount of $94 million and the recovery of this amount through a surcharge of 3.50 mills/kWh for 12 months beginning in June 2007. In addition, the order approved Detroit Edison s proposed PEM reconciliation which was refunded to customers on a bills-rendered basis during June 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 mills 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 included a matrix which provided for different maximum PSCR factors contingent on varying electric Customer Choice sales levels. The plan also included $97 million for recovery of its projected 2005 PSCR under-collection associated with commercial and industrial customers. Additionally, the PSCR plan requested 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 percent to reflect the potential variability in cost projections. The quarterly factors allowed 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. The Company filed its 2006 PSCR reconciliation case in March 2007. The $51 million undercollection amount reflected in that filing is being collected in the 2007 PSCR plan.

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 filing included $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 included 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. 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. The Company began 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. The Company reduced the PSCR factor to 6.69 mills/kWh on July 1, 2007 based on the updated 2007 PSCR Plan year projections.

Uncollectible Expense True-Up Mechanism (UETM) and Report of Safety and Training-Related Expenditures

2005 UETM In March 2006, MichCon filed an application with the MPSC for approval of its uncollectible expense true-up mechanism for 2005. This is the first filing MichCon has made under the uncollectible true-up 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 true-up mechanism allows MichCon to recover ninety percent of uncollectibles that exceeded the $37 million base. Under the formula prescribed by the MPSC, MichCon recorded an under-recovery 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 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 its 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.

2006 UETM In March 2007, MichCon filed an application with the MPSC for approval of its uncollectible expense true-up mechanism for 2006 requesting $33 million of under-recovery plus applicable carrying costs of $3 million. The March 2007 application included a report of MichCon s 2006 annual safety and training related expenditures, which shows a $2 million over-recovery. In August 2007, MichCon filed revised exhibits reflecting an agreement with the MPSC to net the $2 million over-recovery related to the 2006 safety and training related expenditures against the 2006 UETM under-recovery. An MPSC order in this case is expected by the end of 2007.

Gas Cost Recovery Proceedings

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 reconciliation case is still in 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 June 2007, MichCon filed its GCR reconciliation for the 2006-2007 GCR year. The filing supported a total under-recovery, including interest through March 2007, of $18 million. An MPSC order in this case is expected in 2008.

2007-2008 Plan Year / Base Gas Sale Consolidated In August 2006, MichCon filed an application with the MPSC requesting permission to sell base gas that would become accessible with storage facilities upgrades. MichCon s 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. In August 2007, a settlement agreement in this proceeding was reached by all intervening parties that provides for a sharing with customers of the proceeds from the sale of base gas. In addition, the agreement provides for a rate case filing moratorium until January 1, 2009, unless certain unanticipated changes occur that impact income by more than $5 million. The settlement is subject to and has not received MPSC approval.

Other

On July 3, 2007, the Court of Appeals of the State of Michigan published its decision with respect to an appeal by, among others, Detroit Edison, of certain provisions of a November 23, 2004 MPSC order, including reversing the MPSC s denial of recovery of merger control premium costs. DTE Energy and Detroit Edison are continuing to evaluate the Court of Appeals decision. Detroit Edison has not initiated a regulatory proceeding regarding this court decision, but will work with the MPSC to implement it. Given the nature of regulatory proceedings, DTE Energy and Detroit Edison are unable to predict the financial or other outcome of any regulatory action at this time.

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 COMMON STOCK AND EARNINGS PER SHARE

In January 2005, our Board of Directors authorized the repurchase of up to $700 million of common stock through 2008. In May 2007, our Board of Directors authorized the repurchase of up to an additional $850 million of common stock through 2009. Through June 30, 2007, repurchases of approximately $411 million of common stock were made under these authorizations.

Basic earnings per share is computed by dividing income from continuing operations by the weighted average number of common shares outstanding during the period. The calculation of 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. 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. A reconciliation of both calculations is presented in the following table:

	Three Months Ended June 30		**Six Months Ended June 30**	
(Millions, except per share amounts)	**2007**	2006(a)	**2007**	2006
Basic Earnings Per Share				
Income (loss) from continuing operations	**$ 385**	$ (32)	**$ 519**	$ 104
Average number of common shares outstanding	**174**	177	**175**	177
Income (loss) per share of common stock based on weighted average number of shares outstanding	**$ 2.21**	$ (.18)	**$ 2.96**	$ .58
Diluted Earnings Per Share				
Income (loss) from continuing operations	**$ 385**	$ (32)	**$ 519**	$ 104
Average number of common shares outstanding	**174**	177	**175**	177
Incremental shares from stock-based awards	**1**		**1**	1
Average number of dilutive shares outstanding	**175**	177	**176**	178
Income (loss) per share of common stock assuming issuance of incremental shares	**$ 2.20**	$ (.18)	**$ 2.95**	$ .58

(a) Basic and diluted loss per share of common stock for the three month period ended June 30, 2006 are the same because the effect of including stock-based awards in the earnings per share calculation is anti-dilutive.

All options to purchase common stock in the 2007 periods were included in the computation of diluted earnings per share. Options to purchase approximately 4.9 million shares of common stock in 2006, were not included in the computation of diluted earnings per share because the exercise price of the options was greater than the average market price of the common shares, thus making these options anti-dilutive.

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NOTE 8 LONG -TERM DEBT

Debt Retirements and Redemptions

The following debt was retired, through payment at maturity, during 2007:

Company	Month Retired	Type	Interest Rate	Maturity	(in Millions) Amount
MichCon	May	First Mortgage Bonds	7.21%	May 2007	$ 30
			Total Retirements		$ **30**

NOTE 9 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 water intakes. Initially, it was estimated that the Detroit Edison could incur up to approximately $53 million over the three to five years subsequent to 2006 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 dates. The decision also raised the possibility that Detroit Edison 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 manufactured gas plant (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.

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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 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.

The MPSC has established a cost deferral and rate recovery mechanism for investigation and remediation costs incurred at former MGP sites. Accordingly, Gas Utility recognizes a liability and corresponding regulatory asset for estimated investigation and remediation costs at former MGP sites. 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. The reserve balance was $39 million at June 30, 2007.

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 during 2008 at a cost of approximately $15 million. We believe 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 $10 million at June 30, 2007.

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 $380 million at June 30, 2007. This estimated amount fluctuates based upon commodity prices (primarily power and gas) and the provisions and maturities of the underlying agreements.

Labor Contracts

There are several bargaining units for our represented employees. In July 2007, we reached an agreement, pending ratification by bargaining unit members, on all substantive issues necessary to reach a tentative agreement with the union representing 3,111 of our represented employees. In addition, 975 employees are under contracts that expire in October 2007. The contracts of the remaining represented employees expire at various dates in 2008 and 2009.

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Purchase 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 totaling $27 million at June 30, 2007 is being amortized to fuel, purchased power and gas expense with non-cash accretion expense being recorded through 2008. We annually purchased approximately $42 million of steam and electricity in each of 2006, 2005 and 2004. We estimate steam and electric purchase commitments from 2007 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 guaranteed bank loans of $12.5 million that Thermal Ventures II, LP may use for capital improvements to the steam heating system. During the six months ended June 30, 2007, we recorded a $6.8 million reserve related to the bank loan guarantee.

As of June 30, 2007, 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 from 2007 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 that we can estimate and are 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 Contingencies

Detroit Edison and DTE Coal Services Inc. are involved in a contract dispute with BNSF Railway Company that was referred to arbitration. Under this contract, BNSF transports western coals east for Detroit Edison and DTE Coal Services. We filed a breach of contract claim against BNSF for the failure to provide certain services that we believe are required by the contract. We received a partial decision from the arbitration panel in August 2007 which held that BNSF is required to provide such services under the contract. A final decision, which will be subject to an appeal process, is expected in the third quarter of 2007. While we believe that the arbitration panel s decision will be upheld if it is appealed, a negative decision on appeal could have an adverse effect on our ability to grow the Coal Transportation and Marketing business 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, additional 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 we can estimate and 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 periods they are resolved.

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See Note 2 for a discussion of contingencies related to synfuel operations and Note 6 for a discussion of contingencies related to regulatory matters.

NOTE 10 SEGMENT INFORMATION

In 2006, we realigned the non-utility segment Power and Industrial Projects business unit to separately present the Synthetic Fuel business and we separated the Fuel Transportation and Marketing segment into Coal and Gas Midstream and Energy Trading. 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 to approximately 17,000 customers in Adrian, Michigan.

Non-Utility Operations

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

Unconventional Gas Production, consisting of unconventional gas project development and production;

Power and Industrial Projects, consisting of projects that deliver energy and utility-type products and services to industrial, commercial and institutional customers, and biomass energy projects;

Energy Trading, 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 period segment information has been reclassified to conform to the segment structure of the current period.

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:

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(in Millions)	Three Months Ended June 30 2007	2006	Six Months Ended June 30 2007	2006
Electric Utility	**$ 5**	$ 15	**$ 9**	$ 31
Coal and Gas Midstream	**70**	41	**108**	80
Unconventional Gas Production	**33**	31	**63**	71
Energy Trading	**9**	15	**17**	26
	$ 117	$ 102	**$ 197**	$ 208

Financial data of the business segments follows:

(in Millions)	Three Months Ended June 30 2007	2006	Six Months Ended June 30 2007	2006
Operating Revenues				
Electric Utility	**$ 1,210**	$ 1,175	**$ 2,304**	$ 2,225
Gas Utility	**311**	234	**1,185**	1,111
Non-utility Operations:				
Coal and Gas Midstream	**247**	146	**474**	314
Unconventional Gas Production (1)	**(287)**	24	**(259)**	46
Power and Industrial Projects	**123**	100	**233**	207
Energy Trading	**212**	133	**424**	378
Synthetic Fuel	**262**	189	**529**	463
	557	592	**1,401**	1,408
Corporate & Other	**1**	2	**2**	4
Reconciliation & Eliminations	**(125)**	(108)	**(208)**	(218)
Total From Continuing Operations	**$ 1,954**	$ 1,895	**$ 4,684**	$ 4,530

(in Millions, except per share data)	Three Months Ended June 30 2007	2006	Six Months Ended June 30 2007	2006
Net Income (Loss) by Segment:				
Electric Utility	**$ 60**	$ 57	**$ 100**	$ 116
Gas Utility	**(7)**	(14)	**60**	36
Non-utility Operations:				
Coal and Gas Midstream	**11**	10	**23**	23
Unconventional Gas Production (1)	**(211)**	2	**(209)**	3
Power and Industrial Projects	**6**	(1)	**10**	(24)
Energy Trading	**(13)**	(23)	**(12)**	5
Synthetic Fuel	**37**	(34)	**75**	(13)
Corporate & Other (2)	**502**	(29)	**472**	(42)

Income (Loss) from Continuing Operations				
Utility	**53**	43	**160**	152
Non-utility	**(170)**	(46)	**(113)**	(6)
Corporate & Other	**502**	(29)	**472**	(42)
	385	(32)	**519**	104
Discontinued Operations		(1)		(2)
Cumulative Effect of Accounting Change				1
Net Income (Loss)	**$ 385**	$ (33)	**$ 519**	$ 103

(1) 2007 Operating Revenues and Net Loss include recognition of losses on hedge contracts associated with the Antrim sale transaction. See Note 4.

(2) 2007 Net Income results principally from the gain recognized on the Antrim sale transaction. See Note 4.

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Other Information

Risk Factors

In addition to the risk factors discussed below and other information set forth in this report, the risk factors discussed in Part 1, Item 1A. Company Risk Factors in DTE Energy Company s 2006 Form 10-K, which could materially affect the Company s businesses, financial condition and/or future operating results, should be carefully considered. Additional risks and uncertainties not currently known to the Company, or that are currently deemed to be immaterial, also may materially adversely affect the Company s business, financial condition and/or future operating results.

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 2007, we estimate the threshold price at which the tax credit would begin to be reduced is $56 per barrel and would be completely phased out if the Reference Price reached $71 per barrel. As of June 30, 2007, the average NYMEX daily closing price of a barrel of oil was approximately $66 for 2007, equating to an estimated Reference Price of $60, which we estimate to be within the phase-out range.

A work interruption may adversely affect us. Unions represent approximately 5,300 of our employees. A union choosing to strike as a negotiating tactic would have an impact on our business. There are several bargaining units for our represented employees. In July 2007, we reached an agreement, subject to ratification by bargaining unit members, on all substantive issues necessary to reach a tentative agreement with the union representing 3,111 of our represented employees. In addition, 975 employees are under contracts that expire in October 2007. The contracts of the remaining represented employees expire at various dates in 2008 and 2009. We are unable to predict the effects a work stoppage would have on our costs of operation and financial performance.

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. The second phase of implementation began in April 2007 and continued into the third quarter of 2007. Failure to successfully implement new processes and new core information systems could interrupt our operations.

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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 Securities Exchange Act of 1934 during the quarter ended June 30, 2007:

Period		Total Number of Shares Purchased (1)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Dollar Value that May Yet Be Purchased Under the Plans or Programs (2)
04/01/07	04/30/07	75,500	$ 48.62		$ 605,523,194
05/01/07	05/31//07	1,550	$ 52.23	1,771,000	$ 1,362,982,121
06/01/07	06/30/07		$ 50.01	4,481,832	$ 1,138,745,816
		77,050		6,252,832	

(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 of Directors authorized the repurchase of up to $700 million of common

stock through 2008. In May 2007, the DTE Energy Board of Directors authorized the repurchase of up to an additional $850 million of common stock through 2009. Through June 30, 2007, repurchases of approximately $411 million of common stock were made under these authorizations. These authorizations provide management with flexibility to pursue share repurchases from time to time and will depend on actual and future monetizations, cash flows and investment opportunities.

SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

(a) The annual meeting of the holders of Common Stock of the Company was held on May 3, 2007. Proxies for the meeting were solicited pursuant to Regulation 14(a).

(b) There was no solicitation in opposition to the Board of Directors nominees, as listed in the proxy statement, for directors to be elected at the meeting and all such nominees were elected.

The terms of the previously elected six directors listed below continue until the annual meeting dates shown after each name:

Lillian Bauder	2008
Josue Robles, Jr.	2008
Alfred R. Glancy III	2009
John E. Lobbia	2009

Eugene A. Miller	2009
Charles W. Pryor, Jr.	2009

On June 28, 2007, the Board of Directors of the Company elected W. Frank Fountain (effective immediately) and Ruth G. Shaw (effective January 1, 2008) for a term expiring at the earlier of the election or appointment of his or her successor or the 2008 Annual Shareholder Meeting.

(c) At the annual meeting of the holders of Common Stock of the Company held on May 3, 2007, four directors were elected to serve until the annual meeting in the year 2010 and one director (James H. Vandenberghe) was elected to serve until the 2008 Annual Shareholder Meeting with the votes shown:

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	Total Vote For Each Director	Total Vote Withheld From Each Director
Anthony F. Earley, Jr.	134,068,248	3,233,388
Allan D. Gilmour	134,409,097	2,892,539
Frank M. Hennessey	134,763,600	2,538,036
Gail J. McGovern	134,860,393	2,441,243
James H. Vandenberghe	134,915,211	2,386,425

Shareholders ratified the appointment of Deloitte & Touche LLP as the Company s independent registered public accounting firm for the year 2007 with the votes shown:

For	Against	Abstain
134,866,138	1,049,432	1,386,066

There were no shareholder proposals.

(d) Not applicable.

Other Information

The Company has determined that the 2006 Annual Report to Security Holders (Annual Report) as furnished to the Securities and Exchange Commission on April 4, 2007 contains an error. The DTE Consolidated Statement of Changes in Shareholders Equity and Comprehensive Income includes a table detailing comprehensive income, and the amounts reported for pension obligations in the 2006 column of that table are incorrect due to erroneously including the effects of initially adopting SFAS 158. The Company s Form 10-K filed with the Commission on March 1, 2007 includes the correct version of the comprehensive income table. Management also believes that sufficient detail exists in the Annual Report to allow a financial statement user to separately determine the adoption effect of SFAS 158 and other changes in pension obligations. The error will be corrected in the 2007 Annual Report to Security Holders furnished to the Commission in 2008.

Exhibits

Exhibit Number	Description
Filed:	
31-33	Chief Executive Officer Section 302 Form 10-Q Certification
31-34	Chief Financial Officer Section 302 Form 10-Q Certification
Furnished:	
32-33	Chief Executive Officer Section 906 Form 10-Q Certification
32-34	Chief Financial Officer Section 906 Form 10-Q Certification

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

DTE ENERGY COMPANY
(Registrant)

Date: August 14, 2007

/s/ PETER B. OLEKSIAK
Peter B. Oleksiak
Vice President, Controller and
Chief Accounting Officer