DTE ENERGY CO
Form 10-Q
November 09, 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 September 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 September 30, 2007, 163,713,691 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.
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.

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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 utility restructuring in Michigan, including legislative amendments and Customer Choice programs;
- 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;

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- 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;
- amounts of 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.

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.

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 third quarter of 2007 was $197 million, or $1.19 per diluted share, compared to net income of $188 million, or $1.06 per diluted share, in the third quarter of 2006. Net income for the nine months ended September 30, 2007 was $716 million, or $4.15 per diluted share, compared to net income of $291 million, or $1.64 per diluted share in the comparable period of 2006. The increase for the third quarter of 2007 was attributed to higher earnings in our Coal and Gas Midstream, Power and Industrial Projects and Corporate & Other segments, partially offset by lower earnings in our Electric Utility, Gas Utility and Energy Trading segments. The increase for the 2007 nine-month period was primarily due to $364 million in net income resulting from the gain on the sale of the Antrim shale gas exploration and production business of $897 million ($574 million after-tax), partially offset by losses recognized on related hedges of $323 million ($210 million after-tax), including recognition of amounts previously recorded in accumulated other comprehensive income. The 2006 results were adversely impacted by the temporary idling of synfuel plants along with associated impairments and reserves, and higher levels of deferrals of potential gains from selling interests in the synfuel plants. Impairments within our Power and Industrial Projects segment also had a negative impact on the results of the 2006 periods.

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 environmental and reliability-related capital investments.

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 nine months ended September 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 following six months of 2007 compared to the corresponding period of 2006.

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

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. Our doubtful accounts expense for the two utilities increased $12 million for the three months ended September 30, 2007 compared to the comparable period of 2006. We experienced a $1 million increase in doubtful accounts expense to approximately $100 million during the nine months ended September 30, 2007, in comparison to $99 million during the nine months ended September 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. We accrue interest income on the outstanding balances. The following table provides the current amount outstanding and status of each respective year:

(in Millions) Year	Balance at September 30, 2007	Balance at December 31, 2006	Current Regulatory Filing Status
2005 (1)	$ 6	$ 11	Approved in December 2006; actively billing customers
2006(2)	35	34	Reconciliation filed with the MPSC in March 2007
2007(2)	26		Accruing; reconciliation filing scheduled for first quarter 2008
Total	$ 67	$ 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. On August 31, 2007, Detroit Edison filed 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 remanded back to the MPSC the November 2004 order in a prior Detroit Edison rate case that denied recovery of merger control premium costs. Also, the Michigan legislature enacted the Michigan Business Tax (MBT) in July 2007. The supplemental filing addresses the recovery of the merger control premium costs and the enactment of the MBT. The net impact of the supplemental changes results in an additional revenue requirement of approximately $76 million. The general rate case is currently pending with the MPSC and we cannot predict the outcome. 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 $19 million and $53 million in the three and nine months ended September 30, 2007, respectively, as a result of this order. The revenue reduction is net of the recovery of costs associated with 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.

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,

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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 agreement was approved by the MPSC on August 21, 2007. MichCon s gas storage enhancement projects, the main subject of the aforementioned settlement, will enable 17 billion cubic feet (Bcf) of gas to become available for cycling. Under the settlement terms, MichCon will deliver 13.4 Bcf of this gas to its customers at a savings to market-priced supplies of approximately $54 million. This settlement provides for MichCon to retain the proceeds from the sale of 3.6 Bcf of gas, which MichCon expects to sell in 2008 and 2009. By enabling MichCon to retain the profit from the sale of this gas, the settlement provides MichCon with the opportunity to earn an 11% return on equity with no customer rate increase for a period of five years from 2005 to 2010.

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 financing and sale of a 50 percent ownership interest in select projects within the Power and Industrial Projects segment. In addition, we are considering the sale of part of our Barnett shale properties, which may be completed by the end of 2007 or early 2008.

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 plan to continue 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 involved in a contract dispute with BNSF Railway Company that was referred to arbitration. Under this contract, BNSF transports western coal 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 an award from the arbitration panel in September 2007 which held that BNSF is required to provide such services under the contract and awarded damages to us. The award is subject to appeal. While we believe that the arbitration panel s award 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.

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, 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.

In the first nine months of 2007, we continued to develop our position in the Barnett shale basin in north Texas, where our total leasehold acreage is 92,477 (85,480 acres net of interest of others). We continue to acquire select acreage positions in active development areas in the Barnett shale and optimize our existing portfolio.

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 which expired 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.

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 September 30, 2007, we have a series of cash flow hedges for approximately 6.2 Bcf of anticipated Barnett gas production through 2010 at an average price of $7.54 per Mcf.

In August 2007, we announced that we are exploring opportunities to monetize a portion of our interests in the Barnett shale. Currently, we are in discussions with potential buyers of certain properties in the core and southern parts of the Barnett Shale natural gas fields in northern Texas, which involves approximately 41,000 acres in total. We are estimating that any sale may be completed by the end of 2007 or early 2008.

We plan to retain our holdings in the Western portion of the Barnett Shale and anticipate significant opportunities to develop our current position while accumulating additional acreage in and around our existing assets.

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 $107 million in the Barnett Shale for the first nine months of 2007 and expect to invest up to $40 million in the Barnett shale during the remainder of 2007. During 2007, we expect Barnett Shale production of nearly 8.0 Bcfe of natural gas (excluding the impact of potential monetizations) compared with approximately 4.0 Bcfe in 2006.

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 September 30, 2007, this segment owned and operated two 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

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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. The completion of the transaction is subject to the receipt of satisfactory financing arrangements. Our objective is to close the transaction in the fourth quarter 2007, however this timing is highly dependent on the credit markets, and therefore we cannot predict the timing with certainty. 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 for approximately $23 million, which approximated our carrying value. 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 for gross proceeds of approximately $37 million. The sale of the Crete interest closed in October 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 asset portfolio and the optimization of contracted natural gas pipelines and storage capacity positions. Our customer base is predominantly utilities, local distribution companies, pipelines, 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 and power generation capacity positions. Most financial instruments are deemed derivatives, whereas the gas inventory, transmission 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.

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 September 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. 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 increasing the reserve balance by $42 million and $32 million in the three and nine months ended September 30, 2007, respectively. This compares with reducing reserves by $76 million and increasing reserves by $49 million in the three and nine months ended September 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)	$ 64	$ 56	$ 71

The 2007 estimated NYMEX daily closing price of a barrel of oil as of September 30, 2007 averaged approximately $70, which is approximately equal to a Reference Price of $64 per barrel, which we estimate to be approximately 52 percent through the phase-out range. The 2007 estimated NYMEX daily closing price of a barrel of oil as of November 5, 2007 averaged approximately $72, which is approximately equal to a Reference Price of $66 per barrel, which we estimate to be approximately 70 percent through 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. As a result of actual and forward 2007 oil prices, a partial phase-out of the production tax credits in 2007 is probable, which could adversely impact our results of operations, cash flow, and financial condition.

Hedging of Synfuel Cash Flows

As discussed in Note 2 of the Notes to Consolidated Financial Statements, we have entered into derivative and other contracts to economically hedge a portion of our synfuel cash flow exposure to the risk of oil prices increasing. The derivative contracts are marked-to-market with changes in fair value recorded as an adjustment to synfuel gains. 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 gains of $64 million and $44 million during the three and nine months ended September 30, 2007, respectively, and a loss of $24 million and a gain of $83 million during the three and nine months ended September 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 Statements 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 September 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 $38 million and $96 million during the three and nine months ended September 30, 2007, respectively, compared to the recognition of fixed gains of $30 million during the nine months ended September 30, 2006. We did not recognize any fixed gains during the three months ended September 30, 2006. We recognized a loss of $2 million associated with variable payments during the three months ended September 30, 2007, and recognized variable gains of $30 million during the nine months ended September 30, 2007, as compared to the recognition of variable gains of $9 million during the nine months ended September 30, 2006. We did not recognize any variable gains during the three months ended September 30, 2006. 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 nine months ended September 30, 2007, we refunded approximately $81 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

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processes. The CTA in 2006 exceeded our savings, but we expect to begin 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 $8 million during the three and nine months ended September 30, 2007, respectively. During the three and nine months ended September 30, 2007, CTA costs of $18 million and $39 million, respectively, were deferred. MichCon cannot defer CTA costs at this time because a regulatory recovery mechanism has not been established by the MPSC. MichCon expects to seek a recovery mechanism in its next rate case in 2009.

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 $4.5 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 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. 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 $385 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.

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.

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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. 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. 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 third quarter of 2007 was $197 million, or $1.19 per diluted share, compared to net income of $188 million, or $1.06 per diluted share, in the third quarter of 2006. During the nine months ended September 30, 2007, our net income was $716 million, or $4.15 per diluted share, compared to net income of $291 million, or $1.64 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.

	Three Months Ended September 30		**Nine Months Ended September 30**	
(in Millions)	**2007**	2006	**2007**	2006
Net Income (Loss) by Segment:				
Electric Utility	**$ 107**	$ 141	**$ 207**	$ 257
Gas Utility	**(29)**	(20)	**31**	16
Non-utility Operations:				
Coal and Gas Midstream	**15**	10	**38**	33
Unconventional Gas Production (1)	**1**	2	**(208)**	5
Power and Industrial Projects	**3**	(50)	**13**	(74)
Energy Trading	**45**	65	**33**	70
Synthetic Fuel	**45**	43	**120**	30
Corporate & Other (2)	**10**	(2)	**482**	(44)
Income (Loss) from Continuing Operations				
Utility	**78**	121	**238**	273
Non-utility	**109**	70	**(4)**	64
Corporate & Other	**10**	(2)	**482**	(44)
	197	189	**716**	293
Discontinued Operations		(1)		(3)
Cumulative Effect of Accounting Change				1
Net Income	**$ 197**	$ 188	**$ 716**	$ 291

(1) 2007 Net Loss of the Unconventional Gas Production segment during the nine months ended September 30, 2007 resulted principally from the recognition of losses on hedge contracts associated with the Antrim sale transaction in the second quarter of 2007. See Note 4 of the Notes to the Consolidated Financial Statements.

(2) 2007 Net Income of the Corporate & Other segment for the nine months ended September 30, 2007 results principally from the gain recognized on the Antrim sale transaction in the second quarter of 2007. See Note 4 of the Notes to the Consolidated Financial Statements.

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ELECTRIC UTILITY

Our Electric Utility segment consists of Detroit Edison.

Factors impacting income: Net income decreased by $34 million in the third quarter of 2007 and decreased by $50 million in the nine-month period ended September 30, 2007. The decreases were due primarily to higher operation and maintenance expenses, partially offset by lower depreciation and amortization expenses.

	Three Months Ended September 30		Nine Months Ended September 30	
(in Millions)	**2007**	2006	**2007**	2006
Operating Revenues	**$ 1,403**	$ 1,460	**$ 3,707**	$ 3,685
Fuel and Purchased Power	**518**	539	**1,274**	1,257
Gross Margin	**885**	921	**2,433**	2,428
Operation and Maintenance	**386**	277	**1,114**	990
Depreciation and Amortization	**203**	308	**583**	643
Taxes Other Than Income	**63**	64	**204**	198
Other Asset (Gains), Losses and Reserves, Net	**6**	(1)	**12**	(1)
Operating Income	**227**	273	**520**	598
Other (Income) and Deductions	**70**	59	**213**	213
Income Tax Provision	**50**	73	**100**	128
Net Income	**$ 107**	$ 141	**$ 207**	$ 257
Operating Income as a Percent of Operating Revenues	**16%**	19%	**14%**	16%

Gross margin decreased by $36 million in the third quarter of 2007 and increased by $5 million in the nine-month period ended September 30, 2007. The decrease in the third quarter of 2007 was partially due to the favorable impact of a September 2006 MPSC order related to the 2004 PSCR reconciliation, lower rates resulting primarily from the August 2006 settlement in the MPSC show cause proceeding and weather related impacts. The increase in the nine-month period of 2007 was due to the favorable impact of a May 2007 MPSC order related to the 2005 PSCR reconciliation, higher margins due to returning sales from electric Customer Choice and weather related impacts, partially offset by the favorable impact of a September 2006 MPSC order related to the 2004 PSCR reconciliation, 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**	**Nine Months**
Weather related margin impacts	**$ (7)**	$ 21
Return of customers from electric Customer Choice	**4**	47
Service territory economic performance	**(4)**	(25)
Impact of 2006 MPSC show cause order	**(19)**	(53)
Impact of 2005 MPSC PSCR reconciliation order		38
Impact of 2004 MPSC PSCR reconciliation order	**(39)**	(39)
Other, net	**29**	16
Increase (decrease) in gross margin	**$ (36)**	$ 5

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	Three Months Ended September 30	Nine Months Ended September 30
(1) Represents fuel costs associated with power plants.		

	Three Months Ended September 30		Nine Months Ended September 30	
(in Thousands of MWh)	**2007**	2006	**2007**	2006
Electric Sales				
Residential	**4,836**	4,883	**12,340**	12,233
Commercial	**5,166**	4,927	**14,345**	13,440
Industrial	**3,278**	3,695	**9,974**	10,058
Wholesale	**718**	719	**2,170**	2,096
Other	**93**	95	**292**	291
	14,091	14,319	**39,121**	38,118
Interconnections sales (1)	**921**	1,023	**3,120**	2,007
Total Electric Sales	**15,012**	15,342	**42,241**	40,125
Electric Deliveries				
Retail and Wholesale	**14,091**	14,319	**39,121**	38,118
Electric Customer Choice	**389**	319	**1,163**	2,188
Electric Customer Choice Self Generators (2)	**180**	215	**447**	693
Total Electric Sales and Deliveries	**14,660**	14,853	**40,731**	40,999

(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 $109 million for the third quarter of 2007 and by $124 million in the nine-month period ended September 30, 2007. The increase for the quarter was due primarily to a reduction in the deferral of CTA costs of $57 million, EBS implementation costs of $10 million, higher storm expenses of $9 million, increased plant expenses of $7 million, higher uncollectible expense of $5 million, increased corporate support expenses of $8 million and higher labor and benefit costs of $10 million. The increase for the nine-month period is due to EBS implementation costs of $43 million, higher storm expenses of $15 million, higher uncollectible expense of $7 million, increased corporate support expenses of $25 million and higher labor and benefit costs of $21 million. CTA expenses were deferred beginning in the third quarter of 2006. See Note 5 of the Notes to the Consolidated Financial Statements**.**

Depreciation and amortization expense decreased by $105 million for the third quarter of 2007 and decreased by $60 million for the nine-month period ended September 30, 2007. The decrease for the quarter was due primarily to a $112 million net stranded cost write-off related to the September 2006 MPSC order regarding stranded costs. The decrease for the nine-month period was due primarily to a $112 million net stranded cost write-off related to the September 2006 MPSC order regarding stranded costs partially offset by increased amortization of regulatory assets and higher depreciation expense due to increased levels of depreciable plant.

Other asset (gains) losses and reserves, net were $6 million for the third quarter of 2007 and $12 million for the nine-month period ending September 30, 2007, representing reserves for a loan guaranty related to Detroit Edison s former ownership of a steam heating business now owned by Thermal Ventures II, LP (Thermal).

Outlook We will move forward in our efforts to 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. 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 over 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 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

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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 increased by $9 million in the 2007 third quarter and net income increased by $15 million in the 2007 nine-month period. The increased loss in the 2007 third quarter was primarily due to increased operation and maintenance expenses. The improvement in the 2007 nine-month period was due primarily to higher gross margins.

	Three Months Ended September 30		Nine Months Ended September 30	
(in Millions)	**2007**	2006	**2007**	2006
Operating Revenues	**$ 173**	$ 172	**$ 1,358**	$ 1,283
Cost of Gas	**59**	58	**844**	786
Gross Margin	**114**	114	**514**	497
Operation and Maintenance	**106**	93	**330**	327
Depreciation and Amortization	**24**	24	**69**	70
Taxes other than Income	**14**	13	**43**	42
Other Asset (Gains), Losses and Reserves, Net	**(1)**	(3)	**2**	
Operating Income (Loss)	**(29)**	(13)	**70**	58
Other (Income) and Deductions	**10**	14	**28**	39
Income Tax Provision (Benefit)	**(10)**	(7)	**11**	3
Net Income (Loss)	**$ (29)**	$ (20)	**$ 31**	$ 16
Operating Income (Loss) as a Percent of Operating Revenues	**(17)%**	(8)%	**5%**	5%

Gross Margins were flat in the third quarter of 2007 and increased $17 million in the 2007 nine-month period. The increase in the nine-month period is primarily due to $19 million representing the favorable effects of weather in 2007 and $19 million related to an increase in midstream services including storage and transportation, partially offset by a $25 million unfavorable impact in lost gas recognized. Revenues include a component for the cost of gas sold that is recoverable through the GCR mechanism**.**

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	Three Months Ended September 30		Nine Months Ended September 30	
	2007	2006	**2007**	2006
Gas Markets (in Millions)				
Gas sales	**$ 106**	$ 106	**$ 1,118**	$ 1,069
End user transportation	**21**	24	**101**	96
	127	130	**1,219**	1,165
Intermediate transportation	**12**	16	**42**	45
Storage and other	**34**	26	**97**	73
	$ 173	$ 172	**$ 1,358**	$ 1,283
Gas Markets (in Bcf)				
Gas sales	**11**	11	**103**	95
End user transportation	**25**	27	**97**	98
	36	38	**200**	193
Intermediate transportation	**85**	77	**307**	284
	121	115	**507**	477

Operation and maintenance expense increased $13 million in the third quarter of 2007 and $3 million in the 2007 nine-month period. The 2007 third quarter increase was due primarily to $13 million in higher labor and benefit costs and $7 million of higher uncollectible expense, partially offset by a decrease of $10 million of CTA expenses. The 2007 nine-month increase was attributed to $16 million in higher labor and benefit costs partially offset by $6 million of lower uncollectible expense and a decrease of $10 million of CTA expenses.

Depreciation and amortization expense was consistent in the third quarter of 2007 and decreased $1 million in the 2007 nine-month period.

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 continue to 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 $5 million higher in the third quarter of 2007 due primarily to lower operation and maintenance expenses. Net income was also higher by $5 million in the 2007 nine-month period due to increased volumes related to coal marketing, coal-to-power tolling transactions and purchases, sales of emission credits and higher midstream gas storage revenues. Both 2007 periods were impacted by increased interest expense related to the debt assumed in October 2006, that was offset by lower third party storage lease costs, related to the acquisition of the Washington 10 gas storage field.

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	Three Months Ended September 30		Nine Months Ended September 30	
(in Millions)	**2007**	2006	**2007**	2006
Operating Revenues	**$ 187**	$ 187	**$ 661**	$ 501
Operation and Maintenance	**161**	171	**595**	451
Depreciation and Amortization	**3**	1	**6**	3
Taxes other than Income	**1**	2	**4**	4
Other Asset (Gains), Losses and Reserves, net			**(1)**	
Operating Income	**22**	13	**57**	43
Other (Income) and Deductions	**(1)**	(2)	**(3)**	(7)
Income Tax Provision	**8**	5	**22**	17
Net Income	**$ 15**	$ 10	**$ 38**	$ 33

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 an award from the arbitration panel in September 2007 which held that BNSF is required to provide such services under the contract and awarded damages to us. The award is subject to appeal. While we believe that the arbitration panel s award 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. 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. In addition, Vector Pipeline will be requesting permission from the FERC in the fourth quarter of 2007 to build one more compressor station and to expand the Vector Pipeline by approximately 100 MMcf/d, with a proposed in-service date of November 1, 2009. Adding another compressor station will bring the system from its 2007 expanded capacity of about 1.2 Bcf/d up to 1.3 Bcf/d in 2009. 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: Net income was $1 million for the 2007 third quarter, while a net loss of $208 million was incurred in the 2007 nine-month period. This compares with income of $2 million and $5 million in the comparable 2006 periods. As subsequently discussed, in addition to the absence of operating revenues pertaining to Antrim effective in the third quarter of 2007, the significant decline in results in the 2007 nine-month period reflects the recording of $323 million in losses on financial contracts that hedged our price risk exposure.

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(in Millions)	Three Months Ended September 30 **2007**	2006	Nine Months Ended September 30 **2007**	2006
Operating Revenues	**$ 15**	$ 26	**$ (244)**	$ 72
Operation and Maintenance	**5**	9	**30**	27
Depreciation, Depletion and Amortization	**4**	7	**18**	19
Taxes Other Than Income	**1**	2	**8**	8
Other Asset (Gains) and Losses, Reserves and Impairments, Net		1	**9**	1
Operating Income (Loss)	**5**	7	**(309)**	17
Other (Income) and Deductions	**4**	3	**11**	9
Income Tax Provision (Benefit)		2	**(112)**	3
Net Income (Loss)	**$ 1**	$ 2	**$ (208)**	$ 5

Operating revenues decreased $11 million in the 2007 third quarter and $316 million in the 2007 nine-month period. The decrease for the 2007 third quarter resulted primarily from the absence of operating revenues associated with Antrim, which was sold in June 2007. In addition to the absence of operating revenues due to the Antrim sale, the decline for the nine-month period reflects 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 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 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 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 for the first nine months of 2007 by $323 million.

Outlook In August 2007, we announced that we are exploring opportunities to monetize a portion of our interests in the Barnett shale. Currently, we are in discussions with potential buyers of certain properties in the core and southern parts of the Barnett Shale natural gas fields in northern Texas, which involves approximately 41,000 acres in total. We are estimating that any sale may be completed by the end of 2007 or early 2008.

We plan to retain our holdings in the Western portion of the Barnett Shale and anticipate significant opportunities to develop our current position while accumulating additional acreage in and around our existing assets.

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 $107 million in the Barnett Shale for the first nine months of 2007 and expect to invest up to $40 million in the Barnett shale during the remainder of 2007. During 2007, we expect Barnett Shale production of nearly 8.0 Bcfe of natural gas (excluding the impact of potential monetizations) compared with approximately 4.0 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 $3 million in the third quarter of 2007 compared to a net loss of $50 million in the third quarter of 2006. Net income was $13 million in the 2007 nine-month period compared to a net loss of $74 million in the comparable 2006 period. The 2006 periods reflect impairments at various businesses and projects in the Power and Industrial segment.

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(in Millions)	Three Months Ended September 30 2007	2006	Nine Months Ended September 30 2007	2006
Operating Revenues	**$ 127**	$ 105	**$ 360**	$ 312
Operation and Maintenance	**118**	92	**317**	275
Depreciation and Amortization	**10**	13	**30**	37
Taxes other than Income	**3**	3	**9**	10
Other Asset (Gains) and Losses, Reserves and Impairments, Net	**(1)**	48	**(1)**	64
Operating Income (Loss)	**(3)**	(51)	**5**	(74)
Other (Income) and Deductions	**(3)**	30	**5**	40
Minority Interest	**(1)**	1	**(3)**	1
Income Taxes				
Benefit		(29)	**(1)**	(36)
Production Tax Credits	**(2)**	(3)	**(9)**	(5)
	(2)	(32)	**(10)**	(41)
Net Income (Loss)	**$ 3**	$ (50)	**$ 13**	$ (74)

Operating revenues increased $22 million in the 2007 third quarter and $48 million in the 2007 nine-month period. The increases reflect two new automotive projects that began earning revenue in the current year in addition to higher volumes at several other projects in 2007. Additionally, revenue was earned for a one-time success fee from the sale of an asset we operated for a third party.

Operation and maintenance expense increased $26 million in the 2007 third quarter and $42 million in the 2007 nine-month period resulting from increased costs due to two new automotive projects and higher volumes at several other projects.

Other asset (gains) and losses, reserves and impairments, net decreased $49 million in the 2007 third quarter and decreased $65 million in the 2007 nine-month period. During the third quarter of 2006, we recorded a $41 million impairment for one of our 100% owned natural gas-fired electric generating plants and a $3 million impairment at our landfill gas recovery unit in association with the write down of assets at several landfill sites. Additionally, during 2006, we recorded an impairment loss of $20 million ($16 million in the first quarter of 2006 and $4 million in the third quarter of 2006) for the write down of fixed assets and patents at our waste coal recovery business.

Other (income) and deductions decreased $33 million in the 2007 third quarter and $35 million in the 2007 nine-month period primarily due to a $31 million impairment of a 50% equity interest in a natural gas-fired generating plant in 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. The completion of the transaction is subject to the receipt of satisfactory financing arrangements. Our objective is to close the transaction in the fourth quarter 2007, however this timing is highly dependent on the credit markets, and therefore we cannot predict the timing with certainty. 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.

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Energy Trading

Our Energy Trading segment focuses on physical power and gas marketing, structured transactions, enhancement of returns from DTE Energy s asset portfolio, optimization of contracted natural gas pipelines and storage capacity positions, and contractual power generation and transmission positions.

Factors impacting income: Energy Trading s net income decreased $20 million in the third quarter of 2007 and decreased $37 million in the 2007 nine-month period. The decreases in the third quarter of 2007 and in the nine-month period of 2007 are attributed to lower gross margins and an increase in other deductions.

	Three Months Ended September 30		Nine Months Ended September 30	
(in Millions)	**2007**	2006	**2007**	2006
Operating Revenues	**$ 304**	$ 231	**$ 728**	$ 609
Fuel, Purchased Power and Gas	**203**	115	**599**	453
Gross Margin	**101**	116	**129**	156
Operation and Maintenance	**17**	17	**41**	43
Depreciation and Amortization	**1**	2	**3**	4
Taxes Other Than Income			**1**	1
Operating Income	**83**	97	**84**	108
Other (Income) and Deductions	**15**		**34**	3
Income Tax Provision (Benefit)	**23**	32	**17**	35
Net Income	**$ 45**	$ 65	**$ 33**	$ 70

Gross margin decreased $15 million during the 2007 third quarter and decreased $27 million in the 2007 nine-month period. The decrease in the third quarter of 2007 is due to gas margin unfavorability of $62 million primarily from lower mark-to-market gains, partially offset by higher power and oil margins of $35 million and $12 million, respectively. During 2007, we performed analyses of the energy markets and its participants, including an evaluation of liquidity. As a result, we revised our valuation estimates for the long-dated portions of our energy contracts. These analyses resulted in the recognition of approximately $39 million of mark-to-market gains in our power strategies in the third quarter of 2007. Favorable oil margins were primarily due to higher gains on open positions and will reverse by the end of this year as the underlying non-derivative positions are expected to settle by the end of 2007. The decrease in the nine-month period of 2007 is primarily due to unfavorability of $66 million resulting from mark-to-market losses of approximately $30 million for gas contracts related to the aforementioned analyses of energy markets and unfavorability of approximately $36 million resulting from other gas margin mark-to-market activity. The decrease is partially offset by higher power and oil margins of $28 million and $11 million, respectively. Contributing to the favorability in our power strategies is the aforementioned mark-to-market favorability of $39 million for power contracts recorded during the third quarter of 2007. Favorable oil margins were primarily due to higher gains on open positions and will reverse by the end of this year as the underlying non-derivative positions are expected to settle by the end of 2007.

Other (income) and deductions increased by $15 million and $31 million in the 2007 third quarter and 2007 nine-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, causing volatility in reported net income until the swaps and transportation positions are settled.

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, natural gas pipelines, and 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 futures and over-the-counter forwards and swaps. This results in gains and losses that are recognized in different interim and annual accounting periods.

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See Fair Value of Contracts section that follows.

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. The synthetic fuel plants generate operating losses which we expect to be offset by production tax credits, assuming no phase-out.

Factors impacting income: Net income increased $2 million in the 2007 third quarter and increased $90 million in the 2007 nine-month period due to synfuel production occurring throughout the 2007 periods in comparison to the 2006 periods when production was idled at all nine of our synfuel facilities beginning in May 2006.

	Three Months Ended September 30		**Nine Months Ended September 30**	
(in Millions)	**2007**	2006	**2007**	2006
Operating Revenues	**$ 277**	$ 142	**$ 806**	$ 605
Operation and Maintenance	**329**	152	**967**	705
Depreciation and Amortization	**1**	1	**4**	23
Taxes other than Income	**(5)**	1	**3**	8
Other Asset (Gains) and Losses, Reserves and Impairments, Net	**(67)**	(50)	**(144)**	52
Operating Income (Loss)	**19**	38	**(24)**	(183)
Other (Income) and Deductions	**(1)**	(2)	**(7)**	(15)
Minority Interest	**(46)**	(11)	**(161)**	(191)
Income Taxes				

Operating revenues increased $135 million in the third quarter of 2007 and increased $201 million in the 2007 nine-month period. Revenues increased in the 2007 periods due to production throughout 2007 compared to 2006 when production was idled at all nine of our synfuel facilities beginning in May 2006.

Operation and maintenance expense increased $177 million in the third quarter of 2007 and increased $262 million in the 2007 nine-month period. The increase is attributed to the production throughout 2007 in comparison to 2006 when production was idled at all nine of our synfuel facilities.

Depreciation and amortization expense remained the same for the 2007 third quarter and decreased $19 million in the 2007 nine-month period. Depreciation was lower for the nine-month period as a result of lower asset carrying values due to 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 $17 million in the third quarter of 2007 and increased $196 million in the 2007 nine-month period. The increase in gains reflects the annual partner payment adjustment in the second quarter of 2007, 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 nine month periods in 2007 and 2006.

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	Three Months Ended September 30		Nine Months Ended September 30	
(in Millions)	**2007**	2006	**2007**	2006
Components of Synfuel (Gains) Losses, Reserves and Impairments, Net				
(Gains) recognized associated with fixed payments	**$ (38)**	$	**$ (96)**	$ (30)
(Gains) losses recognized associated with variable payments	**2**		**(30)**	(9)
Reserves (reversed) recorded for contractual partners obligations	**42**	(76)	**32**	49
Other reserves and impairments	**(9)**	2	**(6)**	125
Hedge (gains) losses (mark-to-market)				
Hedges for 2006 exposure		13		(73)
Hedges for 2007 exposure	**(64)**	11	**(44)**	(10)
	$ (67)	$ (50)	**$ (144)**	$ 52

Minority interest increased $35 million in the third quarter of 2007 and decreased $30 million in the 2007 nine-month period. The amounts reflect our partners share of operating losses associated with synfuel operations. The increase for the third quarter reflects the increased operating losses due to production throughout the 2007 third quarter as compared to 2006 when production was idled at all nine of our synfuel facilities. The decrease for the nine-month period primarily reflects the decrease in 2007 losses due to the 2006 one-time impairment charges, partially offset by the increased production in 2007.

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 by $12 million in the 2007 third quarter and increased $526 million in the 2007 nine-month period. The increase in the 2007 third quarter is mainly due to favorable adjustments to normalize the effective income tax rate. The increase in the 2007 nine-month period is primarily attributed to the gain on the sale of the Antrim shale gas exploration and production business of approximately $897 million ($574 million after-tax). 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 nine months ended September 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

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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 nine months ended September 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 nine months of 2007, our cash requirements were met primarily through operations, the proceeds received from the sale of the Antrim shale gas exploration and production business and short-term borrowings. We believe that we will have sufficient internal and external capital resources to fund anticipated capital and operating requirements.

	Nine Months Ended September 30	
(in Millions)	**2007**	2006
Cash and Cash Equivalents		
Cash Flow From (Used For):		
Operating activities:		
Net income	**$ 716**	$ 291
Depreciation, depletion and amortization	**716**	801
Deferred income taxes	**90**	24
Gain on sale of non-utility business	**(897)**	
Gain on sale of synfuel and other assets, net	**(130)**	(73)
Working capital and other	**297**	140
	792	1,183
Investing activities:		
Plant and equipment expenditures utility	**(750)**	(830)
Plant and equipment expenditures non-utility	**(206)**	(214)
Acquisitions, net of cash acquired		(27)
Proceeds from sale of non-utility business	**1,258**	
Proceeds from sale of synfuel and other assets, net	**287**	247
Restricted cash and other investments	**3**	(16)
	592	(840)
Financing activities:		
Issuance of long-term debt and common stock		554
Redemption of long-term debt	**(340)**	(672)
Short-term borrowings, net	**(62)**	44

Repurchase of common stock	**(686)**	(10)
Dividends on common stock and other	**(280)**	(282)
	(1,368)	(366)
Net Increase (Decrease) in Cash and Cash Equivalents	**$ 16**	$ (23)

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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 $792 million in the 2007 nine-month period decreased $391 million from the comparable 2006 period. The operating cash flow comparison primarily reflects a decrease in net income after adjusting for non-cash items (depreciation, depletion and amortization and deferred taxes) and gains on sales of businesses.

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. The completion of the transaction is subject to the receipt of satisfactory financing arrangements. Our objective is to close the transaction in the fourth quarter 2007, however this timing is highly dependent on the credit markets, and therefore we cannot predict the timing with certainty. 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 nine-month period compared to the same 2006 period. The 2007 change was primarily related to the sale of our Antrim shale gas exploration and production business and lower capital expenditures.

Financing Activities

Net cash used for financing activities increased $1 billion in the 2007 nine-month period, compared to the same 2006 period, primarily related to repurchase of common stock, decrease in short-term borrowings and issuance of long-term debt, partially offset by a decrease in debt redemptions.

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.

We expect to retire a total of $700 million of debt during 2007 and 2008, and 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

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$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 September 30, 2007 amounting to over $700 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 Statements 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 Statements 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, broker quotes 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.

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.

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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.

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 nine months ended September 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	22	2	21	45	17	62
Changes in fair value recorded to income	26	(27)	28	27	(176)	(149)
Amortization of option premiums	(9)	(2)		(11)		(11)
Amounts recorded to unrealized income	39	(27)	49	61	(159)	(98)
Amounts recorded in Other Comprehensive Income					1	1
Transfer of contracts between Trading and Non-Trading Activities		(323)		(323)	323	
Option premiums paid and other	(8)	17		9	6	15
MTM at September 30, 2007	$ 22	$ (335)	$ 13	$ (300)	$ 147	$ (153)

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 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 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 Statements of Financial Position as of September 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.

	Trading Activities: Proprietary	Trading Activities: Structured	Trading Activities: Economic	Other Non-Trading	Total Assets

(in Millions)	Trading	Contracts	Hedges	Eliminations	Totals	Activities	(Liabilities)
Current assets	$ 82	$ 137	$ 26	$ (26)	$ 219	$ 153	$ 372
Noncurrent assets	3	144	13	(4)	156		156
Total MTM assets	85	281	39	(30)	375	153	528
Current liabilities	(61)	(207)	(21)	26	(263)	(4)	(267)
Noncurrent liabilities	(2)	(409)	(5)	4	(412)	(2)	(414)
Total MTM liabilities	(63)	(616)	(26)	30	(675)	(6)	(681)
Total MTM net assets (liabilities)	$ 22	$ (335)	$ 13	$	$ (300)	$ 147	$ (153)

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Maturity of Fair Value of MTM Energy Contract Net Assets

We manage our mark-to-market risk on a portfolio basis based upon the delivery period of our contracts and the individual components of the risks within each contract. Accordingly, we record and manage the energy purchase and sale obligations under our contracts in separate components based on the commodity (e.g. electricity or gas), the product (e.g. electricity for delivery during peak or off-peak hours), the delivery location (e.g. by region), the risk profile (e.g. forward or option), and the delivery period (e.g. by month and year).

We determine the MTM adjustment for our derivative contracts from a combination of active quotes, published indexes and mathematical valuation models. We generally 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. For periods in which external market data is not readily observable, we estimate value using mathematical valuation models. We periodically update our policy and valuation methodologies for changes in market liquidity and other assumptions which may impact the estimated fair value of our derivative contracts. During 2007, we performed analyses of the energy markets and its participants, including an evaluation of liquidity. As a result, we revised our policy and valuation estimates for the portions of our contracts that extend beyond the actively traded period. Accordingly, our natural gas and power contracts are marked through 2014 and 2011, respectively. 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.

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	$ 25	$ (3)	$	$	$ 22
Structured Contracts	(3)	(83)	(74)	(175)	(335)
Economic Hedges	6	9	(3)	1	13
Total Energy Trading Activities	28	(77)	(77)	(174)	(300)
Other Non-Trading Activities	147	2	(2)		147
Total	$ 175	$ (75)	$ (79)	$ (174)	$ (153)

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, heating oil, foreign currency 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, crude oil, heating oil and foreign currency 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 September 30, 2007:

(in Millions)	Credit Exposure before Cash Collateral	Cash Collateral	Net Credit Exposure
Investment Grade (1)			
A- and Greater	$ 456	$ (33)	$ 423
BBB+ and BBB	176		176
BBB-	47		47
Total Investment Grade	679	(33)	646
Non-investment grade (2)	49	(5)	44

Internally Rated	investment grade (3)		68		(1)		67
Internally Rated	non-investment grade (4)		11		(8)		3
Total		$	807	$	(47)	$	760

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(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 approximately 27 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 approximately four 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 approximately four 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 approximately one 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 September 30, 2007, the Company had a floating rate debt to total debt ratio of approximately 18 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 September 30, 2007 by a hypothetical 10 percent and calculating the resulting change in the fair values.

The results of the sensitivity analysis calculations follow:

(in Millions) Activity	Assuming a 10% increase in rates	Assuming a 10% decrease in rates	Change in the fair value of
Gas Contracts	$ (15)	$ 15	Commodity contracts
Power Contracts	$ (16)	$ 16	Commodity contracts
Oil Contracts	$ 118	$ (98)	Commodity options
Interest Rate Risk	$ (296)	$ 320	Long-term debt
Foreign Currency Risk	$ 1	$ (1)	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 September 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 has not been completed 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 September 30, 2007 that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

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DTE Energy Company
Consolidated Statements of Operations (unaudited)

(in Millions, Except per Share Amounts)	Three Months Ended September 30 2007	Three Months Ended September 30 2006	Nine Months Ended September 30 2007	Nine Months Ended September 30 2006
Operating Revenues	**$ 2,417**	$ 2,196	**$ 7,101**	$ 6,726
Operating Expenses				
Fuel, purchased power and gas	**763**	629	**2,596**	2,277
Operation and maintenance	**1,081**	771	**3,249**	2,698
Depreciation, depletion and amortization	**249**	355	**716**	801
Taxes other than income	**71**	74	**279**	249
Gain on sale of non-utility business (Note 4)			**(897)**	
Other asset (gains) and losses, reserves and impairments, net	**(64)**	(6)	**(122)**	116
	2,100	1,823	**5,821**	6,141
Operating Income	**317**	373	**1,280**	585
Other (Income) and Deductions				
Interest expense	**131**	123	**402**	390
Interest income	**(11)**	(9)	**(32)**	(34)
Other income	**(27)**	(17)	**(51)**	(41)
Other expenses	**17**	38	**51**	58
	110	135	**370**	373
Income Before Income Taxes and Minority Interest	**207**	238	**910**	212
Income Tax Provision	**55**	59	**352**	109
Minority Interest	**(45)**	(10)	**(158)**	(190)
Income from Continuing Operations	**197**	189	**716**	293
Loss from Discontinued Operations, net of tax		(1)		(3)
Cumulative Effect of Accounting Change, net of tax				1
Net Income	**$ 197**	$ 188	**$ 716**	$ 291

Basic Earnings per Common Share				
Income from continuing operations	**$ 1.20**	$ 1.07	**$ 4.17**	$ 1.65
Discontinued operations		(.01)		(.02)
Cumulative effect of accounting change				.01
Total	**$ 1.20**	$ 1.06	**$ 4.17**	$ 1.64
Diluted Earnings per Common Share				
Income from continuing operations	**$ 1.19**	$ 1.07	**$ 4.15**	$ 1.65
Discontinued operations		(.01)		(.02)
Cumulative effect of accounting change				.01
Total	**$ 1.19**	$ 1.06	**$ 4.15**	$ 1.64
Weighted Average Common Shares Outstanding				
Basic	**165**	177	**172**	177
Diluted	**166**	178	**173**	178
Dividends Declared per Common Share	**$ .53**	$ .515	**$ 1.59**	$ 1.545

See Notes to Consolidated Financial Statements (Unaudited)

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DTE Energy Company
Consolidated Statements of Financial Position (unaudited)

(in Millions)	September 30 2007	December 31 2006
ASSETS		
Current Assets		
Cash and cash equivalents	$ 156	$ 147
Restricted cash	93	146
Accounts receivable (less allowance for doubtful accounts of $180 and $170, respectively)		
Customer	1,192	1,427
Collateral held by others	73	68
Other	292	442
Accrued power and gas supply cost recovery revenue	116	117
Inventories		
Fuel and gas	570	562
Materials and supplies	186	153
Deferred income taxes	366	245
Assets from risk management and trading activities	372	461
Other	239	193
Current assets held for sale	74	--
	3,729	3,961
Investments		
Nuclear decommissioning trust funds	826	740
Other	453	505
	1,279	1,245
Property		
Property, plant and equipment	18,834	19,224
Less accumulated depreciation and depletion	(7,496)	(7,773)
	11,338	11,451
Other Assets		
Goodwill	2,042	2,057
Regulatory assets	3,389	3,226
Securitized regulatory assets	1,154	1,235
Intangible assets	28	72
Notes receivable	107	164
Assets from risk management and trading activities	156	164
Prepaid pension assets	77	71

Other		**116**		139
Noncurrent assets held for sale		**411**		**--**
		7,480		7,128
Total Assets	**$**	**23,826**	$	23,785

See Notes to Consolidated Financial Statements (Unaudited)

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DTE Energy Company
Consolidated Statements of Financial Position (unaudited)

(in Millions, Except Shares)	September 30 2007	December 31 2006
LIABILITIES AND SHAREHOLDERS EQUITY		
Current Liabilities		
Accounts payable	**$ 952**	$ 1,145
Accrued interest	**126**	115
Dividends payable	**87**	94
Short-term borrowings	**1,069**	1,131
Current portion of long-term debt, including capital leases	**466**	354
Liabilities from risk management and trading activities	**267**	437
Deferred gains and reserves	**347**	208
Other	**602**	680
Current liabilities associated with assets held for sale	**49**	
	3,965	4,164
Long-Term Debt (net of current portion)		
Mortgage bonds, notes and other	**5,563**	5,918
Securitization bonds	**1,065**	1,185
Trust preferred-linked securities	**289**	289
Capital lease obligations	**44**	82
	6,961	7,474
Other Liabilities		
Deferred income taxes	**1,739**	1,465
Regulatory liabilities	**1,185**	765
Asset retirement obligations	**1,225**	1,221
Unamortized investment tax credit	**111**	120
Liabilities from risk management and trading activities	**414**	259
Liabilities from transportation and storage contracts	**131**	157
Accrued pension liability	**397**	388
Accrued postretirement liability	**1,424**	1,414
Deferred gains	**15**	36
Nuclear decommissioning	**129**	119
Other	**324**	312
Noncurrent liabilities associated with assets held for sale	**71**	
	7,165	6,256
Commitments and Contingencies (Notes 2, 6 and 9)		
Minority Interest	**38**	42

Shareholders Equity				
Common stock, without par value, 400,000,000 shares authorized, 163,713,691 and 177,138,060 shares issued and outstanding, respectively		**3,181**		3,467
Retained earnings (less FIN 48 cumulative effect adjustment of $5 in 2007)		**2,634**		2,593
Accumulated other comprehensive loss		**(118)**		(211)
		5,697		5,849
Total Liabilities and Shareholders Equity	**$**	**23,826**	$	23,785

See Notes to Consolidated Financial Statements (Unaudited)

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DTE Energy Company
Consolidated Statements of Cash Flows (Unaudited)

	Nine Months Ended September 30	
(in Millions)	**2007**	2006
Operating Activities		
Net Income	**$ 716**	$ 291
Adjustments to reconcile net income to net cash from operating activities:		
Depreciation, depletion and amortization	**716**	801
Deferred income taxes	**90**	24
Gain on sale of interests in synfuel projects	**(144)**	(72)
Gain on sale of non-utility business	**(897)**	
Other asset (gains), losses and reserves, net	**14**	(1)
Impairment of synfuel projects		124
Partners share of synfuel project losses	**(161)**	(191)
Contributions from synfuel partners	**177**	155
Cumulative effect of accounting change		(1)
Changes in assets and liabilities, exclusive of changes shown separately	**281**	53
Net cash from operating activities	**792**	1,183
Investing Activities		
Plant and equipment expenditures utility	**(750)**	(830)
Plant and equipment expenditures non-utility	**(206)**	(214)
Acquisitions, net of cash acquired		(27)
Proceeds from sale of interests in synfuel projects	**329**	203
Refunds to synfuel partners	**(81)**	
Proceeds from sale of non-utility business	**1,258**	
Proceeds from sale of other assets, net	**39**	44
Restricted cash for debt redemptions	**52**	29
Proceeds from sale of nuclear decommissioning trust fund assets	**227**	136
Investment in nuclear decommissioning trust funds	**(254)**	(163)
Other investments	**(22)**	(18)
Net cash from (used for) investing activities	**592**	(840)
Financing Activities		
Issuance of long-term debt		545
Redemption of long-term debt	**(340)**	(672)
Short-term borrowings, net	**(62)**	44
Issuance of common stock		9
Repurchase of common stock	**(686)**	(10)
Dividends on common stock	**(278)**	(274)
Other	**(2)**	(8)
Net cash used for financing activities	**(1,368)**	(366)

Net Increase (Decrease) in Cash and Cash Equivalents		**16**		(23)
Cash and Cash Equivalents Reclassified to Assets Held for Sale		**(7)**		
Cash and Cash Equivalents at Beginning of the Period		**147**		88
Cash and Cash Equivalents at End of the Period	**$**	**156**	$	65

See Notes to Consolidated Financial Statements (Unaudited)

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DTE Energy Company
Consolidated Statements 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			716		716
Implementation of FIN 48			(5)		(5)
Pension and postretirement obligations, net of tax				3	3
Dividends declared on common stock			(272)		(272)
Repurchase and retirement of common stock	(14,235)	(288)	(398)		(686)
Net change in unrealized gains on derivatives, net of tax				91	91
Net change in unrealized losses on investments, net of tax				(1)	(1)
Stock-based compensation	811	2			2
Balance, September 30, 2007	**163,714**	**$ 3,181**	**$ 2,634**	**$ (118)**	**$ 5,697**

The following table displays comprehensive income for the nine-month periods ended September 30:

(in Millions)	**2007**	2006
Net income	**$ 716**	$ 291
Other comprehensive income (loss), net of tax:		
Pension and postretirement obligations, net of taxes of $2 and $, respectively	**3**	
Net unrealized gains (losses) on derivatives:		
Gains (losses) arising during the period, net of taxes of $(76) and $79, respectively	**(141)**	146
Amounts reclassified to income, net of taxes of $125 and $(32), respectively	**232**	(59)
	91	87
Net unrealized gains (losses) on investments:		
Losses arising during the period, net of taxes of $(2) and $(3), respectively	**(3)**	(6)
Amounts reclassified from income, net of taxes of $1 and $, respectively	**2**	
	(1)	(6)
Comprehensive income	**$ 809**	$ 372

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 nine-month period follows:

(in Millions)	
Asset retirement obligations at January 1, 2007	$ 1,221
Accretion	59
Liabilities incurred	1
Liabilities settled	(20)
Assets held for sale	(13)
Revision in estimated cash flows	3
Asset retirement obligations at September 30, 2007	1,251
Less amount included in current liabilities	(26)
	$ 1,225

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.

Goodwill

Goodwill decreased $15 million during the nine months ended September 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.

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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 September 30, 2007 was $34 million and $6 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 million and $4 million for the nine months ended September 30, 2007 and 2006, respectively. Amortization expense of intangible assets is estimated to be $4 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 September 30	**2007**	2006	**2007**	2006
Service cost	**$ 16**	$ 16	**$ 17**	$ 13
Interest cost	**46**	44	**28**	30
Expected return on plan assets	**(59)**	(56)	**(17)**	(17)
Amortization of				
Net loss	**16**	15	**18**	19
Prior service cost (credit)	**2**	2	**(1)**	(1)
Transition liability			**3**	2
Special termination benefits	**3**	19		3
Net periodic benefit cost	**$ 24**	$ 40	**$ 48**	$ 49

Nine Months Ended September 30	**2007**	2006	**2007**	2006
Service cost	**$ 47**	$ 48	**$ 47**	$ 44
Interest cost	**134**	132	**89**	87
Expected return on plan assets	**(179)**	(167)	**(50)**	(46)
Amortization of				
Net loss	**44**	45	**51**	54
Prior service cost (credit)	**4**	6	**(2)**	(2)
Transition liability			**5**	5
Special termination benefits	**8**	34	**2**	4
Net periodic benefit cost	**$ 58**	$ 98	**$ 142**	$ 146

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 $30 million at January 1, 2007 and September 30, 2007, respectively. The decline in unrecognized tax benefits during the nine months ended September 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 $15 million at September 30, 2007, if recognized, would favorably impact our effective tax rate. During the next twelve months, statutes of limitations will expire for our tax returns in various states. We do not anticipate any significant changes to our unrecognized tax benefits for these events.

We recognize interest and penalties pertaining to income taxes in Interest expense and Other expenses, respectively, on our Consolidated Statements of Operations. Accrued interest pertaining to income taxes totaled $8 million and $7 million at January 1, 2007 and September 30, 2007, respectively. We had no accrued penalties pertaining to income taxes. We recognized an interest expense reduction of $0.5 million related to income taxes during the three months ended September 30, 2007. We recognized interest expense related to income taxes of $0.7 million during the nine months ended September 30, 2007, compared to $0.9 million and $1.5 million during the three and nine months ended September 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 MBT provides credits for Michigan business investment, compensation, and research and development. The MBT will be accounted for as an income tax.

Effective with the enactment of the MBT in the third quarter of 2007, a state deferred tax liability of $241 million was recognized by the Company for cumulative differences between book and tax assets and liabilities for the consolidated group. Effective September 30, 2007, legislation was adopted by the State of Michigan creating a deduction for businesses that realize an increase in their deferred tax liability due to the enactment of the MBT. Therefore, a deferred tax asset of $241 million was established related to the future deduction. The deduction will be claimed during the period of 2015 through 2029. The recognition of the enactment of the MBT did not have an impact on our income tax provision for the three and nine months ended September 30, 2007.

Of the $241 million of deferred tax liabilities and assets recognized for the consolidated group, $341 million related to our regulated entities with the remainder related to our non-regulated entities. The $341 million of deferred tax liabilities and assets recognized by our regulated utilities were offset by corresponding regulatory assets and liabilities in accordance with SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation,* as the impacts of the deferred tax liabilities and assets recognized upon enactment and amendment of the MBT will be reflected in our rates.

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Stock-Based Compensation

DTE Energy has long-term stock incentive plans that permit the granting 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 September 30		Nine Months Ended September 30	
(in Millions)	**2007**	2006	**2007**	2006
Stock-based compensation expense	**$ 8**	$ 4	**$ 27**	$ 17
Tax benefit of compensation expense	**$ 2**	$ 2	**$ 9**	$ 6

Compensation cost capitalized in property, plant and equipment was $1.5 million and $2 million during the nine months ended September 30, 2007 and 2006, respectively.

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 for the nine months ended September 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 nine months ended September 30, 2007:

	Number of Options	Weighted Average Exercise Price
Outstanding at December 31, 2006	5,667,197	$ 41.60
Granted	419,400	$ 47.57
Exercised	(1,542,899)	$ 41.36
Forfeited, Expired or Canceled	(34,093)	$ 43.37
Outstanding at September 30, 2007	4,509,605	$ 42.22
Exercisable at September 30, 2007	3,417,614	$ 41.22

As of September 30, 2007, the weighted average remaining contractual life for the exercisable shares is 5.12 years. During the first nine months of 2007, 874,650 options vested. As of September 30, 2007, 1,091,991 options were non-vested. Generally, our stock options vest over a three year period.

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

	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
Risk-free interest rate	4.71%	4.87%
Dividend yield	4.38%	4.99%
Expected volatility	17.99%	19.25%
Expected life	6 years	6 years

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Stock Awards

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

	Restricted Stock	Weighted Average Grant Date Fair Value
Balance at December 31, 2006	666,136	$ 43.20
Grants	612,550	$ 49.48
Forfeitures	(35,202)	$ 44.66
Vested	(221,362)	$ 41.28
Balance at September 30, 2007	1,022,122	$ 47.34

Performance Share Awards

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

	Performance Shares
Balance at December 31, 2006	1,035,696
Grants	489,765
Forfeitures	(64,853)
Payouts	(267,265)
Balance at September 30, 2007	1,193,343

Unearned Compensation Cost

As of September 30, 2007, there was $51 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 1.36 years.

Consolidated Statements of Cash Flows

A detailed analysis of the changes in assets and liabilities that are reported in the Consolidated Statements of Cash Flows follows:

(in Millions)	Nine Months Ended September 30 2007	2006
Changes in Assets and Liabilities, Exclusive of Changes Shown Separately		
Accounts receivable, net	**$ 383**	$ 546
Accrued GCR revenue	**(37)**	149
Inventories	**(45)**	(143)
Accrued/Prepaid pensions	**3**	94
Accounts payable	**(176)**	(260)
Accrued PSCR refund	**2**	(162)
Income taxes payable	**(112)**	29
Risk management and trading activities	**127**	(266)
Postretirement obligation	**10**	16
Other assets	**(353)**	(143)
Other liabilities	**479**	193

	$ 281	$ 53

Supplementary cash and non-cash information follows:

	Nine Months Ended September 30	
(in Millions)	**2007**	2006
Cash Paid for		
Interest paid (excluding interest capitalized)	**$ 392**	$ 376
Income taxes paid, net of refunds	**$ 314**	$ 53

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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 $47 million and $23 million at September 30, 2007 and December 31, 2006, respectively.

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 Statements of Operations:

(in Millions)	Three Months Ended September 30		Nine Months Ended September 30	
Description	**2007**	2006	**2007**	2006
Synfuels:				
(Gains) recognized for fixed payments	**$ (38)**	$	**$ (96)**	$ (30)
(Gains) losses recognized for variable payments	**2**		**(30)**	(9)
Reserves (reversed) recorded for contractual partners obligations	**42**	(76)	**32**	49
Other reserves and impairments	**(9)**	2	**(6)**	125
Hedge (gains) losses (mark-to-market)	**(64)**	24	**(44)**	(83)
Synfuels, net	**(67)**	(50)	**(144)**	52
Other Non-utility:				
Waste coal recovery		4		20
Landfill gas recovery		3		3
Power generation	**(1)**	41	**(1)**	41
Barnett shale		1	**9**	1
Electric utility	**6**	(1)	**12**	(1)
Gas utility	**(1)**	(3)	**2**	
Other	**(1)**	(1)		
	$ (64)	$ (6)	**$ (122)**	$ 116

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 September 30, 2007, we have generated and recorded approximately $606 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 September 30, 2007, the 2007 estimated NYMEX daily closing price of a barrel of oil was approximately $70 for 2007, equating to an estimated Reference Price of $64, which we estimate to be approximately 52 percent through the phase-out range. The 2007 estimated NYMEX daily closing price of a barrel of oil as of November 5, 2007 averaged approximately $72, which is approximately equal to a Reference Price of $66 per barrel, which we estimate to be approximately 70 percent through 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.

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

Through September 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.

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 September 30, 2007, fixed gains recognized totaled $38 million, while no such gains were recognized during the third quarter of 2006. During the nine months ended September 30, 2007 and 2006, fixed gains recognized totaled $96 million and $30 million, respectively. We recognized a loss of $2 million associated with variable payments during the third quarter of 2007. We recognized no variable gains during the third quarter of 2006. During the nine months ended September 30, 2007 and 2006, variable gains recognized totaled $30 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 $81 million to our partners in the first nine 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 increasing the reserve balance by $42 million and $32 million in the three and nine months ended September 30, 2007. We recorded reserves for contractual partners obligations of $125 million through the second quarter of 2006. During the third quarter of 2006, we reversed $76 million of reserves due to the resumption of synfuel production.

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 gain of $64 million in the third quarter of 2007 compared to a pre-tax loss of $24 million during the third quarter of 2006, while such changes were a pre-tax gain of $44 million in the first nine months of 2007 compared to a pre-tax gain of $83 million during the first nine 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 Statements 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 Statements 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. During the third quarter of 2006, we recorded an additional reserve for notes receivable of $2 million. 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 Statements 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 September 30, 2007 is $2.9 billion. At September 30, 2007, we have reserved $340 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 in earnings unrealized gains and losses on items, for which the fair value option has been elected, 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 costs or 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 Statements of Financial Position 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.

Offsetting Amounts Related to Certain Contracts

In April 2007, the FASB issued FSP FIN 39-1, *Amendment of FASB Interpretation No. 39*. This standard will permit us to offset the fair value of derivative instruments with cash collateral received or paid for those derivative instruments executed with the same counterparty under a master netting arrangement. As a result, we will be permitted to record one net asset or liability that represents the total net exposure of all derivative positions under a master netting arrangement. The decision to offset derivative positions under master netting arrangements remains an accounting policy choice. We presently record the net fair value of derivative assets and liabilities for those contracts held by Energy Trading that are subject to master netting arrangements, and separately record amounts for cash collateral received or paid for these instruments. Under this standard, if we choose to offset the collateral amounts against the fair value of derivative assets and liabilities, both our total assets and total liabilities could be reduced. The guidance in this FSP is effective for fiscal years beginning after November 15, 2007, with early application permitted. The standard is to be applied retrospectively by adjusting the financial statements for all periods presented. There will be no impact to earnings for adopting this standard.

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 ($574 million after-tax) and is reported on the Consolidated Statements of Operations for the nine months ended September 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 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, including contract periods that extend beyond the actively traded period. 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 nine months ended September 30, 2007 by $323 million.

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 (Projects). In addition to the proceeds that we will receive from the sale of the 50 percent equity interest, the company that will own the Projects will obtain debt financing and the proceeds will be distributed to us immediately prior to the sale of the equity interest. The total gross proceeds we will receive are expected to be approximately $800 million. The sale is subject to normal closing conditions. The completion of the transaction is subject to the receipt of satisfactory financing arrangements. Our objective is to close the transaction in the fourth quarter 2007, however this timing is highly dependent on the credit markets, and therefore we cannot predict the timing with certainty. We expect to recognize a gain upon completion of the transaction. In conjunction with the sale, we will enter into a management services agreement to manage the day-to-day operations of the Projects and to act as the managing member of the company that owns the Projects. The Projects are contained in the Power and Industrial Projects segment.

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For the three and nine months ended September 30, 2007, the earnings pertaining to the Projects are fully consolidated in our Consolidated Statements of Operations. On September 30, 2007, the assets and liabilities of the Projects initially met the held for sale criteria of SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets.* The following table presents the major classes of assets and liabilities of the Projects classified as held for sale:

(in Millions)		
Cash and cash equivalents	$	7
Restricted cash		1
Accounts receivable		57
Inventories		6
Other current assets		3
Total current assets held for sale		74
Investments		54
Property, plant and equipment, net of accumulated depreciation of $182		266
Intangible assets		39
Long-term notes receivable		52
Total noncurrent assets held for sale		411
Total assets held for sale	$	485
Accounts payable	$	38
Other current liabilities		11
Total current liabilities associated with assets held for sale		49
Long-term debt		51
Asset retirement obligations		13
Other liabilities		7
Total noncurrent liabilities associated with assets held for sale		71
Total liabilities related to assets held for sale	$	120

The table above represents 100 percent of the applicable assets and liabilities that are held for sale as of September 30, 2007. Subsequent to the sale of the 50 percent interest, the remaining 50 percent interest in the Projects will be reflected in our financial statements under the equity method of accounting. The consolidated statement of financial position includes $30 million of minority interests in projects classified as held for sale. The results of the Projects will not be presented as discontinued operations as we will be retaining a 50 percent ownership interest which represents significant continuing involvement as described in paragraph 42 of SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*.

Crete

In July 2007, we entered into an agreement to sell our 50 percent equity interest in Crete, a 320 MW natural gas-fired peaking electric generating plant. The sale closed in October 2007 resulting in gross proceeds of approximately $37 million. We will recognize a gain on the sale in the fourth quarter of 2007.

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 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 nine months ended September 30, 2007 and 2006.

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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 September 30, 2007, Dtech had liabilities of approximately $1.7 million. Dtech did not have significant business activity for the three and nine months ended September 30, 2007 and 2006.

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

Waste Coal Recovery

Through the third quarter of 2006, our Power and Industrial Projects segment recorded a pre-tax impairment loss of $20 million ($16 million in the first quarter and $4 million in the third quarter) 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 Statements of Operations.

Landfill Gas Recovery

During the third quarter of 2006, our Power and Industrial Projects segment recorded a pre-tax impairment loss of $3 million at our landfill gas recovery unit relating to the write down of assets at several landfill sites. The fixed assets were impaired due to continued operating losses and the oil price-related phase-out of production tax credits. The impairment was recorded within the Other asset (gains) and losses, reserves and impairments, net line in the Consolidated Statements of Operations. We calculated the expected undiscounted cash flows from the use and eventual disposition of the assets, which indicated that the carrying amount of certain assets was not recoverable. We determined the fair value of the assets utilizing a discounted cash flow technique.

Non-Utility Power Generation

During the third quarter of 2006, our Power and Industrial Projects segment recorded a pre-tax impairment loss totaling $72 million for its investments in two natural gas-fired electric generating plants.

A loss of $41 million related to a 100% owned plant is recorded within the Other asset (gains) and losses, reserves and impairments, net line in the Consolidated Statements of Operations. The generating plant was impaired due to continued operating losses and the September 2006 delisting by MISO, resulting in the plant no longer providing capacity for the power grid. We calculated the expected undiscounted cash flows from the use and eventual disposition of the plant, which indicated that the carrying amount of the plant was not recoverable. We determined the fair value of the plant utilizing a discounted cash flow technique.

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A loss of $31 million related to a 50 percent equity interest in Crete is recorded within the Other (income) and deductions, other expenses line in the Consolidated Statements of Operations for the three and nine months ended September 30, 2006. The investment was impaired due to continued operating losses and the expected sale of the investment. We determined the fair value of the plant utilizing a discounted cash flow technique, which indicated that the carrying amount of the investment exceeded its fair value.

Restructuring Performance Excellence Process

In mid-2005, we initiated a company-wide review of our operations called the Performance Excellence Process. 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 $8 million for the three and nine months ended September 30, 2007, respectively. Detroit Edison deferred approximately $18 million and $39 million of CTA during the three and nine months ended September 30, 2007, respectively. MichCon cannot defer CTA costs at this time because a recovery mechanism has not been established. MichCon expects to seek a recovery mechanism in its next rate case in 2009. See Note 6.

Amounts expensed are recorded in the Operation and maintenance line on the Consolidated Statements of Operations. Deferred amounts are recorded in the Regulatory assets line on the Consolidated Statements of Financial Position.

Expenses incurred for the three months ended September 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	**$ 16**	$ 10	**$ 19**	$ 28
Gas Utility	**1**	8	**1**	4	**2**	12
Other		1				1
Total costs	**4**	27	**17**	14	**21**	41
Less amounts deferred or capitalized:						
Electric Utility	**3**	36	**16**	41	**19**	77
Amount expensed	**$ 1**	$ (9)	**$ 1**	$ (27)	**$ 2**	$ (36)

Expenses incurred for the nine months ended September 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	**$ 14**	$ 36	**$ 30**	$ 41	**$ 44**	$ 77
Gas Utility	**3**	10	**2**	8	**5**	18
Other	**1**	1		1	**1**	2
Total costs	**18**	47	**32**	50	**50**	97

Less amounts deferred or capitalized:												
Electric Utility		**14**		36		**30**		41		**44**		77
Amount expensed	**$**	**4**	$	11	**$**	**2**	$	9	**$**	**6**	$	20

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*.

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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 $27 million was credited to the unrecovered regulatory asset in the nine months ended September 30, 2007.

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 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.

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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.

On August 31, 2007, Detroit Edison filed a supplement to its April 2007 rate case filing. A July 2007 decision by the Court of Appeals of the State of Michigan remanded back to the MPSC the November 2004 order in a prior Detroit Edison rate case that denied recovery of merger control premium costs. The supplemental filing addressed recovery of approximately $61 million related to the merger control premium. The filing also included the impact of the July 2007 enactment of the Michigan Business Tax (MBT), effective in 2008, of approximately $5 million. In addition, Detroit Edison has included the financial impact of the MBT related to its securitization bonds (Fermi nuclear plant assets) of approximately $12 million, partially offset by other adjustments to the original April 2007 rate case filing of $2 million. The net impact of the supplemental changes results in an additional revenue requirement of approximately $76 million annually. 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 nine months ended September 30, 2007, Detroit Edison deferred CTA costs of $18 million and $39 million, respectively. Amortization of prior year deferred CTA costs amounted to $3 million and $8 million during the three and nine months ended September 30, 2007, respectively. MichCon cannot defer CTA costs at this time because a recovery mechanism has not been established. MichCon expects to seek a recovery mechanism in its next rate case in 2009.

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 September 30, 2007, approximately $25 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.

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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 of 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 $13 million, including carrying charges, has been deferred as a regulatory asset. Detroit Edison is authorized to incorporate into its rates an enhanced security factor over a period not to exceed five years. Amortization of this regulatory asset was approximately $2 million in the nine months ended September 30, 2007.

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 requested a 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. In July 2007, the MPSC approved a negotiated RARS deficiency settlement that resulted in a $10 million write down of RARS-related costs in 2007. As previously, discussed above, the CIM in the MPSC Show-Cause Order will reduce the regulatory asset. Approximately $27 million was credited to the unrecovered regulatory asset in the nine months ended September 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 under-collection amount reflected in that filing is being collected in the 2007 PSCR plan. An MPSC order in this case is expected in 2008.

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. In August 2007, the MPSC approved Detroit Edison s 2007 PSCR case and authorized the Company to charge a maximum power supply cost recovery factor of 8.69 mills/kWh in 2007.

2008 Plan Year In September 2007, Detroit Edison filed its 2008 PSCR plan case seeking approval of a levelized PSCR factor of 9.23 mills/kWh above the amount included in base rates for all PSCR customers. The Company is supporting a total 2008 power supply expense forecast of $1.3 billion which includes $1 million for the recovery of its projected 2007 PSCR undercollection. The Company s PSCR Plan will allow the Company to recover its reasonably and prudently incurred power supply expense including; fuel costs, purchased and net interchange power costs, NOx and SO2 emission allowance costs, transmission costs and Midwest Independent Transmission System Operator

(MISO) costs. Also included in the filing is a request for approval of the Company s emission compliance strategy which includes pre-purchases of emission allowances as well as a request for pre-approval of a contract for capacity and energy associated with a renewable (wind energy) project.

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 agreement was approved by the MPSC on August 21, 2007. MichCon s gas storage enhancement projects, the main subject of the aforementioned settlement, will enable 17 billion cubic feet (Bcf) of gas to become available for cycling. Under the settlement terms, MichCon will deliver 13.4 Bcf of this gas to its customers at a savings to market-priced supplies of approximately $54 million. This settlement provides for MichCon to retain the proceeds from the sale of 3.6 Bcf of gas, which MichCon expects to sell in 2008 and 2009. By enabling MichCon to retain the profit from the sale of this gas, the settlement provides MichCon with the opportunity to earn an 11% return on equity with no customer rate increase for a period of five years from 2005 to 2010.

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, The Detroit Edison Company of certain provisions of a November 23, 2004 MPSC order, including reversing the MPSC s denial of recovery of merger control premium costs. In its published decision, the Court of Appeals held that Detroit Edison is entitled to recover its allocated share of the merger control premium and remanded this matter to the MPSC for further proceedings to establish the precise amount and timing of this recovery. As discussed above, Detroit Edison filed a supplement to its April 2007 rate case to address the recovery of the merger control premium costs. Other parties have filed requests for leave to appeal to the Michigan Supreme Court from the Court of Appeals decision. On September 6, 2007, the Court of Appeals remanded to the MPSC, for reconsideration, the MichCon recovery of merger control premium costs. DTE Energy and Detroit Edison are unable to predict the financial or other outcome of any legal or regulatory proceeding 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 September 30, 2007, repurchases of approximately $706 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. Non-vested restricted stock awards are 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:

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(Millions, except per share amounts)	Three Months Ended September 30 2007	2006	Nine Months Ended September 30 2007	2006
Basic Earnings Per Share				
Income from continuing operations	**$ 197**	$ 189	**$ 716**	$ 293
Average number of common shares outstanding	**165**	177	**172**	177
Income per share of common stock based on weighted average number of shares outstanding	**$ 1.20**	$ 1.07	**$ 4.17**	$ 1.65
Diluted Earnings Per Share				
Income from continuing operations	**$ 197**	$ 189	**$ 716**	$ 293
Average number of common shares outstanding	**165**	177	**172**	177
Incremental shares from stock-based awards	**1**	1	**1**	1
Average number of dilutive shares outstanding	**166**	178	**173**	178
Income per share of common stock assuming issuance of incremental shares	**$ 1.19**	$ 1.07	**$ 4.15**	$ 1.65

All options to purchase common stock in the 2007 periods were included in the computation of diluted earnings per share. Options to purchase approximately 4.8 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.

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
DTE Energy	August	Senior Notes	5.63%	Aug. 2007	$ 173
			%		
Total Retirements					$ 203
			%		

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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 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**.**

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 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 September 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.

Non-Utility

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

Millennium Pipeline Project Guarantee

We own a 26.25% equity interest in the Millennium Pipeline Project (Millennium). Millennium is accounted for under the equity method. Millennium is expected to begin commercial operations in November 2008.

On August 29, 2007, Millennium entered into a borrowing facility to finance the construction costs of the project. The total facility amounts to $800 million and is guaranteed by the project partners, based upon their respective ownership percentages. The facility expires on August 29, 2010. The amount outstanding under this facility was $105 million at September 30, 2007. Proceeds of the facility are being used to fund project costs and expenses relating to the development, construction and commercial start up and testing of the pipeline project and for general corporate purposes. In addition, the facility has been utilized to reimburse the project partners for costs and expenses incurred in connection with the project for the period subsequent to June 1, 2004 through immediately prior to the closing of the facility. We received approximately $23.5 million in September 2007 as reimbursement for costs and expenses incurred by us during the above-mentioned period. We accounted for this reimbursement as a return of capital.

We have agreed to guarantee 26.25% of the borrowing facility in the event of default by Millennium. The guarantee includes our DTE Energy revolving credit facility s covenant and default provisions by reference. We have also provided performance guarantees in regards to completion of Millennium to the major shippers in an amount of approximately $16 million. The maximum potential amount of future payments under these guarantees are approximately $226 million. There are no recourse provisions or collateral that would enable us to recover any amounts paid under the guarantees other than our share of project assets. At September 30, 2007, an obligation of $5 million has been accrued related to our guarantee of the borrowing facility. We have increased the carrying amount of our equity investment amount in Millennium by approximately $5 million in association with the recognition of the guarantee obligation. We are amortizing the carrying amount of the guarantee and the above-mentioned increase in our investment in Millennium by the straight-line method over three years, which represents the term of the guarantee.

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 $407 million at September 30, 2007. This estimated amount fluctuates based upon commodity prices (primarily power and gas) and the provisions and maturities of the underlying agreements.

Other Guarantees

Our other guarantees are not individually material with maximum potential payments totaling $10 million at September 30, 2007.

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Labor Contracts

There are several bargaining units for our represented employees. In October 2007, a new three-year agreement was ratified by approximately 950 employees in our gas operations. A July 2007 tentative agreement was not ratified by approximately 3,100 employees in our electric operations. In October 2007, a new tentative agreement was reached, subject to ratification by electric operations bargaining unit members. The contracts of the remaining represented employees expire at various dates in 2008 and 2009**.**

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 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 $24 million at September 30, 2007 is being amortized to fuel, purchased power and gas expense with non-cash accretion expense being recorded through 2008. 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 $13 million that Thermal Ventures II, LP may use for capital improvements to the steam heating system. During the three and nine months ended September 30, 2007, we recorded reserves of $6 million and $13 million, respectively, related to the bank loan guarantee.

As of September 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 approximately $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 an award from the arbitration panel in September 2007 which held that BNSF is required to provide such services under the contract and awarded damages to us. The award is subject to appeal. While we believe that the arbitration panel s award will be upheld if it is appealed, a negative decision on appeal could have an adverse effect on Detroit Edison s business and our ability to grow the Coal Transportation and Marketing business.

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 these pending proceedings is not expected to have a material effect on our operations or financial statements in the periods they are resolved.

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.

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

(in Millions)	Three Months Ended September 30 2007	Three Months Ended September 30 2006	Nine Months Ended September 30 2007	Nine Months Ended September 30 2006
Electric Utility	**$ 20**	$ 15	**$ 29**	$ 46
Gas Utility	**1**	4	**4**	10
Coal and Gas Midstream	**32**	39	**140**	120
Unconventional Gas Production (1)		31	**63**	102
Power and Industrial Projects	**6**	3	**13**	4
Energy Trading	**26**	35	**43**	61
Synthetic Fuel				
Corporate & Other	**(17)**	1	**(16)**	3
	$ 68	$ 128	**$ 276**	$ 346

Financial data of the business segments follows:

(in Millions)	Three Months Ended September 30 2007	Three Months Ended September 30 2006	Nine Months Ended September 30 2007	Nine Months Ended September 30 2006
Operating Revenues				
Electric Utility	**$ 1,403**	$ 1,460	**$ 3,707**	$ 3,685
Gas Utility	**173**	172	**1,358**	1,283
Non-utility Operations:				
Coal and Gas Midstream	**187**	187	**661**	501
Unconventional Gas Production (1)	**15**	26	**(244)**	72
Power and Industrial Projects	**127**	105	**360**	312
Energy Trading	**304**	231	**728**	609
Synthetic Fuel	**277**	142	**806**	605
	910	691	**2,311**	2,099
Corporate & Other	**(1)**	1	**1**	5
Reconciliation & Eliminations	**(68)**	(128)	**(276)**	(346)
Total From Continuing Operations	**$ 2,417**	$ 2,196	**$ 7,101**	$ 6,726

(in Millions)	Three Months Ended September 30 2007	Three Months Ended September 30 2006	Nine Months Ended September 30 2007	Nine Months Ended September 30 2006
Net Income (Loss) by Segment:				

Electric Utility	**$ 107**	$ 141	**$ 207**	$ 257
Gas Utility	**(29)**	(20)	**31**	16
Non-utility Operations:				
Coal and Gas Midstream	**15**	10	**38**	33
Unconventional Gas Production (1)	**1**	2	**(208)**	5
Power and Industrial Projects	**3**	(50)	**13**	(74)
Energy Trading	**45**	65	**33**	70
Synthetic Fuel	**45**	43	**120**	30
Corporate & Other (2)	**10**	(2)	**482**	(44)
Income (Loss) from Continuing Operations				
Utility	**78**	121	**238**	273
Non-utility	**109**	70	**(4)**	64
Corporate & Other	**10**	(2)	**482**	(44)
	197	189	**716**	293
Discontinued Operations		(1)		(3)
Cumulative Effect of Accounting Change				1
Net Income	**$ 197**	$ 188	**$ 716**	$ 291

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(1) Operating Revenues and Net Loss of the Unconventional Gas Production segment for the nine months ended September 30, 2007 reflect the recognition of losses on hedge contracts associated with the Antrim sale transaction and the absence of Antrim operating revenues commencing in the third quarter of 2007. See Note 4.

(2) Net Income of the Corporate & Other segment for the nine months ended September 30, 2007 results principally from the gain recognized on the Antrim sale transaction. See Note 4.

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, future operating results and/or cash flows 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 September 30, 2007, the average NYMEX daily closing price of a barrel of oil was approximately $70 for 2007, equating to an estimated Reference Price of $64, 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 October 2007, a new three-year agreement was ratified by approximately 950 employees in our gas operations. A July 2007 tentative agreement was not ratified by approximately 3,100 employees in our electric operations. In October 2007, a new tentative agreement was reached, subject to ratification by electric operations bargaining unit members. We can provide no assurance that the new tentative agreement will be ratified by the employees in our electric operations. 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 continues throughout 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 September 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)
07/01/07	07/31/07	1,000	$49.15	3,208,538	$ 980,986,679
08/01/07	08/31/07	376,250	$47.85	2,474,986	$ 862,514,949
09/01/07	09/30/07	-	$47.83	380,800	$ 844,294,092
		377,250		6,064,324	

(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 September 30, 2007, repurchases of approximately $706 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.

Other Information

Shareholders Rights Agreement

Our Shareholders Rights Agreement expired by its terms on October 7, 2007 and was not amended, extended or renewed. The Agreement had provided that, upon certain triggering events, each holder of our common stock would be entitled to purchase from us one one-hundredth of a share of Series A Junior Participating Preferred Stock of DTE Energy at a price of $90.

Change-in-Control Severance Agreements

DTE Energy entered into new Change-in-Control Severance Agreements (CIC Agreements) with Anthony F. Earley, Jr., Gerard M. Anderson, Robert J. Buckler and David E. Meador. Each of the CIC Agreements is effective as of November 8, 2007, and replaces previous change-in-control severance agreements between the Company and such named officers. The revisions to the CIC Agreements generally have the effect of limiting the circumstances under which the Company is obligated to make payments to the named officers.

The CIC Agreements were revised primarily to incorporate changes necessary to comply with Section 409A of the Internal Revenue Code of 1986, as amended, relating to deferred compensation. In addition, the CIC Agreements were amended, among other things, (i) to modify certain definitions, generally having the effect of reducing triggering events under the agreements, (ii) to clarify how the named officer s annual bonus is calculated for purposes of the agreement, (iii) to provide for a lump sum payment for welfare benefits (rather than continuation of benefits during the severance period), and (iv) to add non-solicitation, non-disparagement and confidentiality provisions. In addition, under the revised agreement, one-third of the lump sum severance payment will be paid in consideration of a non-competition provision, which will have the effect of reducing the Company s obligation to gross-up the named officer s severance benefits to compensate him for excise taxes.

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Amendment to Executive Supplemental Retirement Plan

On October 30, 2007, the Organization and Compensation Committee of the Board of Directors of the Company approved an amendment to the Company s Executive Supplemental Retirement Plan (ESRP) to reflect certain changes contemplated by the new CIC Agreements.

The descriptions set forth above are qualified in their entirety by reference to the full text of the form of CIC Agreement and the Fourth Amendment to the ESRP which are attached to this Quarterly Report as Exhibits 10.71 and 10.72, respectively, and are hereby incorporated by reference.

Exhibits

Exhibit Number	Description
Filed:	
10-71	Form of Change-in-Control Severance Agreement, dated as of November 8, 2007, between DTE Energy Company and each of Anthony F. Earley, Jr., Gerard M. Anderson, Robert J. Buckler and David E. Meador
10-72	Fourth Amendment to the DTE Energy Company Executive Supplemental Retirement Plan
31-35	Chief Executive Officer Section 302 Form 10-Q Certification
31-36	Chief Financial Officer Section 302 Form 10-Q Certification
Furnished:	
32-35	Chief Executive Officer Section 906 Form 10-Q Certification
32-36	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: November 9, 2007

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