

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

BUSINESS

TXU Corp. is a holding company conducting its operations principally through its TXU Energy Company LLC (TXU Energy Company), TXU Electric Delivery Company (TXU Electric Delivery) and TXU Generation Development Company LLC (TXU DevCo) subsidiaries. TXU Energy Company is a holding company whose subsidiaries are engaged in competitive market activities consisting of electricity generation, retail electricity sales to residential and business customers, wholesale energy sales and purchases as well as commodity risk management and trading activities, all largely in Texas. TXU Electric Delivery is engaged in regulated electricity transmission and distribution operations in Texas. TXU DevCo is engaged in the development of new lignite/coal-fueled generation facilities but is expected to develop those facilities as a subsidiary of TXU Energy Company.

On February 26, 2007, TXU Corp. announced that it had entered into an Agreement and Plan of Merger, dated February 25, 2007 (Merger Agreement), with Texas Energy Future Holdings Limited Partnership (Merger Sub Parent) and Texas Energy Future Merger Sub Corp (Merger Sub), whereby TXU Corp. would merge with Merger Sub, and TXU Corp. would become a wholly-owned subsidiary of Merger Sub Parent. See Note 26 to Financial Statements.

Operating Segments

TXU Corp. has aligned and reports its business activities as two operating segments: TXU Energy Holdings and TXU Electric Delivery.

TXU Energy Holdings segment includes the activities of TXU Energy Company and TXU DevCo, as described above. This segment also includes the activities of a lease trust holding certain natural gas-fueled combustion turbines.

TXU Electric Delivery segment includes the activities of TXU Electric Delivery, as described above, and its wholly owned bankruptcy-remote financing subsidiary.

See Note 24 to Financial Statements for further information concerning reportable business segments.

Business Strategy

Overview

In 2004, TXU Corp. launched a three-phase restructuring program to restore financial strength, drive performance improvement with a competitive industrial company perspective and allocate capital in a disciplined and efficient manner.

- Phase one involved divesting of value-disadvantaged businesses and using the sales proceeds, operating cash flows and cash on hand to simplify the capital structure and improve financial flexibility. This phase also included changing pricing and commodity price hedging strategies to reflect rising natural gas prices, resolving significant litigation risks and lowering business process costs through a significant outsourcing arrangement. Phase one was completed in 2004. As discussed in Note 8 to Financial Statements, these restructuring actions resulted in net charges to 2004 income from continuing operations totaling \$1.2 billion (\$828 million after-tax). Also see Note 3 to Financial Statements for the effect on results from discontinued operations.
- Phase two included implementation of initiatives to achieve operational excellence across the business, targeting industry-leading performance standards for productivity, reliability and customer service and embedding a high-performance industrial culture. Phase two work has been largely completed but remains ongoing as a basis for continuous process improvement.
- Phase three included development and implementation of the growth strategy for TXU Corp. and its two business segments. In 2006, actions were initiated to execute this strategy by way of several key initiatives launched during the year, including planned development of new generation facilities. TXU Corp. has agreed to modify this strategy in connection with the proposed merger.

Following is a discussion of key operating developments in the TXU Energy Holdings and TXU Electric Delivery operating segments.

TXU Energy Holdings Segment Significant Developments

Texas Generation Facilities Development

In 2006, TXU Corp. announced that it intended to develop and construct up to 11 lignite/coal-fueled generation units in central and east Texas, with a total estimated capacity of up to 9,300 MW. In connection with the proposed merger, TXU Corp. has modified its strategy and has reduced the number of lignite/coal-fueled generation units that it intends to develop and construct in Texas from 11 to three units with a total estimated capacity of approximately 2,200 MW.

The three units proposed to be developed consist of one new generation unit at an existing TXU Corp. lignite/coal-fueled generation plant site (Sandow) and two units at a site (Oak Grove) owned by TXU Corp. that was originally slated for the construction of a generation plant a number of years ago. Aggregate capital expenditures for these three units are expected to total approximately \$3.2 billion, including all construction, site preparation and mining development costs.

The development program includes up to \$450 million for investments in state-of-the-art emissions controls for the three proposed units. Further, TXU Corp. expects additional capital expenditures for environmental control systems at existing generation facilities to total up to \$400 million.

Developmental activities are well underway for the three proposed units. TXU Corp. subsidiaries have executed engineering, procurement and construction (EPC) agreements for these units with Bechtel Power Corporation (Bechtel) and Fluor Enterprises, Inc. (Fluor). In addition, to facilitate meeting the expected timeline for the start-up of the new facilities, TXU DevCo or the EPC contractors have placed orders for critical, long lead-time equipment, including boilers, turbine generators and air quality control systems. The EPC contracts for the Sandow unit (with Bechtel) and the two Oak Grove units (with Fluor) are essentially fixed price agreements. Both contracts contain price adjusting provisions, but the price risk is not considered significant to the overall scope and magnitude of the projects.

TXU Corp. expects the TCEQ to issue final air permits for the Oak Grove facility by year-end 2007. Construction of Oak Grove is expected to commence immediately following the issuance of the related air permits. The expected on-line dates of the units are as follows: Sandow in 2009 and Oak Grove's two units in 2009 and 2010.

TXU Corp. will promptly seek to stay the contested cases relating to the permits for seven of the units and suspend processing of the permit application for the one unit that is not subject to a contested case. TXU Corp. intends to withdraw all permit applications for the eight units upon the closing of the proposed merger. If the proposed merger closes, TXU Corp. does not intend to apply or reapply for permits to build additional generation units utilizing current pulverized coal-fueled technology in Texas or in any other US region.

To mitigate risk associated with the development program, TXU DevCo is pursuing opportunities for contractual forward sales of electricity. As a result of this process, TXU DevCo may ultimately enter into sales agreements with municipalities, electric cooperatives and industrial companies with terms ranging from five to over 20 years.

TXU DevCo is subject to writedowns and additional costs arising from the suspension of the development of the eight generation units. Construction work-in-process asset balances totaling approximately \$900 million at February 28, 2007 are subject to impairment. Future penalties and other costs arising from equipment order cancellations and other suspension activities are estimated to total up to approximately \$200 million. The total gross exposure of \$1.1 billion excludes any recovery and salvage amounts, which are currently not estimable. TXU Corp. expects to record a charge in the first quarter of 2007 for these exposures.

On February 27, 2007, TXU DevCo terminated orders with Alstom Power, Inc. for air quality control systems for five units. TXU DevCo is exploring opportunities for redeployment of equipment related to the remaining three units, including use in the environmental retrofit program related to existing generation facilities. On February 28, 2007, TXU DevCo terminated steam turbine generator orders with General Electric Company for eight units. TXU DevCo has suspended or terminated several other equipment orders related to the eight units.

Potential Nuclear Generation Development

As previously disclosed, TXU Corp. also planned to develop applications to file for combined construction and operating licenses for 2,000 to 6,000 MW of new nuclear generation capacity at one to three sites in Texas. TXU Corp. currently plans to develop an application to file for combined licenses for at least one site (up to 3,400 MW of new nuclear generation capacity) at its existing Comanche Peak nuclear generation facility. The Comanche Peak application is expected to be submitted in 2008, which could facilitate bringing the new capacity on-line between 2015 and 2020. Because of regulatory and supply chain uncertainties, TXU Corp. believes that nuclear generation capital costs and development times are currently not competitive with other technologies. TXU Corp. is continuing its ongoing process to resolve these uncertainties and is employing a technical and economic feasibility process with original equipment manufacturers to design a safe and reliable nuclear generation facility and seek to achieve per kilowatt capital costs that are up to 30 to 40 percent lower than current average publicly-announced industry estimates.

Investment in Cleaner Coal-Fueled Generation Technologies

In an initiative separate from but related to the planned generation development and related emissions controls investment spending, subsidiaries of TXU Corp. expect to invest up to \$2 billion over the next five to seven years for the development and commercialization of cleaner generation plant technologies, including integrated gasification combined cycle, the next generation of more efficient ultra-supercritical coal and pulverized coal emissions technology to reduce CO₂ emissions. TXU Corp. has already initiated a number of actions, including research and development investments and partnerships, to advance next-generation technologies.

Long-term Hedging Program

During 2006, TXU Corp. significantly expanded its long-term hedging program, commenced in October 2005, designed to reduce exposure to changes in future electricity prices due to changes in the price of natural gas. Under the program, subsidiaries of TXU Corp. have entered into market transactions involving natural gas-related financial instruments. Including the TXU DevCo hedge transactions discussed immediately below, as of February 28, 2007 subsidiaries of TXU Corp. have effectively sold forward an outstanding 1.95 billion MMBtu of natural gas (an equivalent of over 220,000 GWh) over the period 2007 to 2012 at average annual prices ranging from \$7.06 per MMBtu to \$9.62 per MMBtu, including a net 1.3 billion MMBtu in instruments that have been accounted for as cash flow hedges. The balance of the hedge transactions are marked-to-market in net income.

As part of the long-term hedging program, TXU DevCo has entered into the following transactions:

- In June 2006, TXU DevCo entered into a related series of hedging transactions under an agreement that allows hedging of movements in electricity prices. See Note 19 to Financial Statements for a discussion of a loss of \$109 million (\$71 million after-tax) recorded upon inception of these hedging transactions. This agreement was amended and restated in February 2007.
- In February 2007, TXU DevCo entered into a series of hedging transactions under an agreement that allows hedging of movements in electricity prices. A “day one” loss of approximately \$70 million (\$46 million after-tax) is expected to be recorded in the first quarter of 2007 to recognize the below-market pricing of the transactions.

Initially, TXU DevCo’s hedging transactions under these agreements will be secured by a first-lien security interest in the two lignite/coal-fueled generation units at TXU Energy Company’s Big Brown plant and will also be guaranteed by TXU Energy Company. Upon certain events, including the closing of the proposed merger, these hedging transactions will be transferred to TXU Energy Company and will be supported by a first-lien security interest in TXU Energy Company’s assets.

While there is significant correlation in the movement of natural gas prices and wholesale electricity prices in ERCOT because marginal demand is generally met with gas-fueled generation plants, electricity prices do not always move in tandem with natural gas prices. Given the size of the hedge program and the cross-commodity nature of the hedges, the program may result in greater volatility of net income due to cash flow hedge ineffectiveness gains and losses, as well as greater mark-to-market gains and losses on positions not accounted for as cash flow hedges, than TXU Corp. has experienced in recent years. For example, based on the position at December 31, 2006, a change of 0.1 (or 1%) in forward market heat rates could result in cash flow hedge ineffectiveness gains or losses of up to \$220 million pretax. In 2006, TXU Corp. recorded unrealized mark-to-market and cash flow hedge ineffectiveness net gains of \$231 million related to positions in the long-term hedging program, including a \$109 million loss on inception of certain hedging transactions (see Note 18 to Financial Statements). Cash flow hedge net gains on positions in the program that have been deferred in accumulated other comprehensive income as effective totaled \$432 million after-tax as of December 31, 2006.

TXU Electric Delivery Segment Significant Developments

New Utility Services Joint Venture

In the second quarter of 2006, TXU Corp. and InfrastruX Group announced the formation of a joint venture, InfrastruX Energy Services, that expects to provide utility construction, power restoration, maintenance and other services. TXU Corp. also announced an agreement between TXU Electric Delivery and InfrastruX Energy Services under which TXU Electric Delivery will receive services from the joint venture. The contractual amount of the services agreement is \$8.7 billion over the 10-year term.

Under the terms of the joint venture arrangement, over 2,000 current TXU Electric Delivery employees are expected to be employed by the joint venture. These employees represent essentially all of TXU Electric Delivery's field operations personnel, consisting primarily of construction, maintenance and engineering staff. InfrastruX Group expects to contribute all its operations to the joint venture, including its 3,000 current employees. These operations generated revenues of approximately \$400 million in 2005. In addition, TXU Corp. expects to contribute approximately \$30 million in tools and other equipment to the joint venture and also expects to sell approximately \$60 million in inventory, principally poles and wire, to the joint venture in exchange for a 10-year note receivable. TXU Electric Delivery expects to incur transition expenses related to the arrangement of up to \$19 million, of which \$7 million was expensed in 2006. TXU Corp. and InfrastruX Group will have equal representation on the joint venture's board of directors. Allocations and distributions of profits, losses and cash from the joint venture to the partners are to be primarily based upon the performance of the TXU Corp.-related and InfrastruX-related legacy operations.

The Commission recently expressed its desire to gather further information regarding the joint venture. TXU Corp. cannot predict the ultimate outcome of this process, including its possible effect on the timing of closure of the transaction. Also see discussion below under "Regulation and Rates".

Technology Initiatives

In 2006, TXU Electric Delivery finalized an agreement with CURRENT Communications Group, LLC (CURRENT), to utilize TXU Electric Delivery's power distribution network as a broadband-enabled "Smart Grid." CURRENT plans to design, build and operate the "broadband over power line" (BPL) network covering the majority of the TXU Electric Delivery service area. Build-out of the BPL network began in 2006 with the installation of fiber optic cable and additional investment in advanced data management systems. This modernized grid is expected to enhance TXU Electric Delivery's ability to deliver top decile electric service reliability and provide the potential for additional products and services from REPs that will enable businesses and consumers to manage their electricity usage and costs. Under the terms of the agreement with CURRENT, TXU Electric Delivery expects to incur service fees totaling approximately \$150 million over a 10 year period commencing in 2007 to utilize the Smart Grid capabilities of CURRENT's BPL network.

Overlaid on the existing electric distribution network, the CURRENT BPL network solution will incorporate advanced digital communication and computing capabilities that, for the first time, provide real-time monitoring through the electric distribution network, enabling TXU Electric Delivery to:

- increase network reliability and power quality;
- prevent, detect and restore customer outages more effectively; and
- implement advanced meter monitoring more efficiently.

Additionally, CURRENT will use the same BPL network to provide homes and businesses with high-performance broadband and wireless services, including voice, video and high-speed Internet access, provided over existing electrical lines by having customers simply plug into any electrical outlet.

TXU Corp. has made a small investment to acquire a noncontrolling interest in CURRENT. Other CURRENT investors include energy, financial services and technology companies.

To take full advantage of the BPL network, TXU Electric Delivery has initiated replacement of existing meters with advanced digital metering technology. Installation of these advanced meters is expected to speed connects/disconnects of electric service where applicable and ultimately facilitate the creation of new products and service offerings by REPs, including time-of-use options and various new billing methods. TXU Electric Delivery has installed 285,000 advanced meters as of December 31, 2006 and plans to install up to 500,000 additional advanced meters in 2007. TXU Electric Delivery expects to replace all of its 3 million meters with advanced meters under this technology initiative by 2012, for a total investment of approximately \$450 million. Texas legislation provides for the recovery of and return on a utility's investment related to advanced metering technology to incent electricity delivery utilities to invest in this new technology.

KEY RISKS AND CHALLENGES

Following is a discussion of the key risks and challenges facing management and the initiatives currently underway to manage such challenges:

Natural Gas Price and Market Heat-Rate Exposure

Wholesale electricity prices in the Texas market generally move with the price of natural gas because marginal demand for electricity supply is generally met with natural gas-fueled generation plants. Natural gas prices have increased significantly in recent years, but historically the price has fluctuated due to the effects of weather, changes in industrial demand and supply availability, and other economic and market factors. Wholesale electricity prices also move with market heat rates. Heat rate is the measure of the efficiency of the marginal supplier (generally natural gas-fueled plants) in generating electricity. The wholesale market price of power divided by the market price of natural gas represents the market heat rate.

In contrast to TXU Corp.'s natural gas-fueled generation units, changes in natural gas prices have no significant effect on the cost of generating electricity from TXU Corp.'s nuclear and lignite/coal-fueled plants. All other factors being equal, these baseload generation assets, which provided 70% of supply volumes in 2006, increase or decrease in value as natural gas prices rise or fall, respectively, because of the effect of natural gas prices on wholesale power prices.

With the exposure to variability of natural gas prices, retail sales price management and hedging activities are critical to the profitability of the business. With the expiration of the price-to-beat rate mechanism on January 1, 2007 (see discussion below under "Regulation and Rates"), TXU Corp. has price flexibility in all of its retail markets.

Considering forecasted electricity supply and sales load and wholesale market positions, TXU Corp.'s portfolio position for 2007 is largely balanced with respect to changes in natural gas prices. The supply and load forecast take into account projections of baseload unit availability and customer churn and currently assumes no further changes in retail rates for customers not already on a fixed price contract.

TXU Corp.'s approach to managing commodity price risk focuses on the following:

- improving customer service to attract and retain high-value customers;
- continuing to follow a retail pricing strategy that appropriately reflects the magnitude and costs of commodity price risk;
- continuing reduction of fixed costs to better withstand gross margin volatility; and
- employing disciplined hedging and risk management strategies through physical and financial energy-related (electricity and natural gas) contracts to partially hedge gross margins.

As discussed above under "TXU Energy Holdings Segment Significant Developments", TXU Corp. has implemented a long-term hedging program to mitigate the risk of future declines in wholesale electricity prices due to declines in natural gas prices.

The following scenarios are presented to quantify the potential impact of movements in natural gas prices and market heat rates. Illustratively, if TXU Energy Holdings' sales prices immediately and fully adjusted to reflect changes in wholesale electricity prices due to changes in natural gas prices, and taking into account the hedges in place at year-end 2006 under the long-term hedging program expected to settle in 2007, TXU Corp. could experience an approximate \$300 million reduction in annual pretax earnings for every \$1.00 per MMBtu reduction in natural gas prices (approximate 14% change in current price) sustained over the full year. In the same scenario of full and immediate pass-through of wholesale electricity price changes to sales prices, where natural gas prices and other nonprice conditions remained unchanged but ERCOT wholesale electricity prices declined by \$5/MWh (approximate 9% change in current price) for a full year because of a decline in market heat rates, TXU Corp. could experience an approximate \$300 million reduction in annual pretax earnings.

The long-term hedging program does not mitigate exposure to changes in market heat rates. TXU Corp.'s market heat rate exposure derives from its generation portfolio and may increase over time with expected generation capacity increases. TXU Corp. expects that increases in market heat rates would increase the value of its generation assets because higher market heat rates generally result in higher wholesale electricity prices, and vice versa.

On an ongoing basis, TXU Corp. will continue monitoring its overall commodity risks and seek to balance its portfolio based on its desired level of exposure to natural gas prices and market heat rates and potential changes to its operational forecasts of overall generation and consumption in its native and growth business. Portfolio balancing may include the execution of incremental transactions or the unwinding of existing transactions. As a result, commodity price exposures and their effect on earnings could change from time to time.

See "Liquidity and Capital Resources" below for a discussion of the liquidity effects of the long-term hedging program. Also see additional discussion of risk measures below under "Quantitative and Qualitative Disclosure About Market Risk."

Competitive Markets and Customer Retention

Competitive retail activity in Texas continued to result in declines in customer counts and sales volumes in the historical service territory. Total retail sales volumes declined 11%, 17% and 12% in 2006, 2005 and 2004, respectively, as retail sales volume declines in the historical service territory were partially offset by growth in other territories. The area representing TXU Corp.'s historical service territory prior to deregulation, largely in north Texas, consisted of approximately 3 million electricity consumers (measured by meter counts) as of year-end 2006. TXU Corp. currently has approximately 1.9 million retail customers in that territory and has acquired approximately 256,000 retail customers in other competitive areas in Texas. In responding to the competitive landscape and the transition to full competition in the Texas marketplace on January 1, 2007, TXU Corp. is focusing on the following key initiatives:

- Customer retention strategy remains focused on delivering world-class customer service and improving the overall customer experience. In line with this strategy, TXU Corp. continues to implement initiatives to improve call center response time and effectiveness as well as Internet interaction with customers;
- TXU Energy Company intends to establish itself as the most innovative retailer in the Texas market as it is critical in the fully competitive environment and continues to develop tailored product offerings to meet customer needs;
- A comprehensive customer initiative to provide residential customers with greater savings and price certainty was introduced in the fourth quarter of 2006. This initiative included a \$100 customer appreciation bonus (see Note 7 to Financial Statements), a \$25 incentive to customers who switch from the basic rate (former price-to-beat rate) plan to a discounted rate plan, and a three-year rate cap for customers who remain on plans with the basic rate; and
- Initiatives in the business market are focused largely on programs targeted to retain the existing highest-value customers and to recapture customers who have switched REPs. Initiatives include a more disciplined contracting and pricing approach and improved economic segmentation of the business market to enhance targeted sales and marketing efforts and to more effectively deploy the direct-sales force. Tactical programs put into place include improved customer service, new product price/service offerings and a multichannel approach for the small business market.

TXU Corp. has announced that in connection with the proposed merger, effective with March 27, 2007 meter reads, TXU Energy will provide a six percent price discount to those customers in the historical service territory that have month-to-month service plans with a rate equivalent to the former price-to-beat rate. Further, upon closing of the merger, TXU Energy intends to provide an additional four percent discount and also provide price protection through 2008 to those customers. The aggregate ten percent price discounts are expected to provide total annual savings of more than \$300 million to those customers.

Texas Generation Development Program

The undertaking of the development of three generation units in Texas as described above under “TXU Energy Holdings Segment Significant Developments” involves a number of risks. Aggregate capital expenditures to develop these three units are expected to total approximately \$3.2 billion. While TXU Corp. believes the investment economics of the program are strong, estimates of future natural gas prices, market heat rates, air permit grant dates and effects of any CO₂ emissions regulation may prove to be inaccurate, and returns on the investment could be significantly less than anticipated. Financing of the program, which has not yet been finalized, may result in higher interest costs than expected and could negatively impact liquidity. The program is exposed to construction delays, failure of the units to meet performance specifications, nonperformance by equipment suppliers, increases in construction labor costs (contractually limited in part) and other project execution risks. Further, project capital spending for the three units continues despite increasing public discussion of the advantages and disadvantages of coal-fueled generation and the absence of final air permits. Should these development activities be canceled, TXU Corp. is exposed to impairment of construction work-in-process assets and project discontinuance costs, including equipment order cancellation penalties (see Note 16 to Financial Statements). Management has evaluated the potential risks and benefits of the program to both Texas consumers and TXU Corp. and believes that in consideration of the most likely market and performance scenarios, continued progress towards completion of the program is the appropriate course of action.

Energy Prices and Regulatory Risk

Natural gas prices rose to unprecedented levels in the latter part of 2005, reflecting a world-wide increase in energy prices compounded by hurricane-related infrastructure damage. The related rise in retail electricity prices elevated public awareness of energy costs and dampened customer demand in 2006. Natural gas prices have since declined but remain subject to events that create price volatility. Sustained high energy prices and/or ongoing price volatility also creates a risk for regulatory and/or legislative intervention with the mechanisms that govern the competitive wholesale and retail markets in Texas. TXU Corp. believes that competitive markets result in a broad range of innovative pricing and service alternatives to consumers and ultimately the most efficient use of resources, and that regulatory bodies should continue to take actions that encourage competition in the industry.

New and Changing Environmental Regulations

TXU Corp. is subject to various environmental laws and regulations related to SO₂, NO_x and mercury emissions as well as other environmental contaminants that impact air and water quality. TXU Corp. is in compliance with all current laws and regulations, but regulatory authorities continue to evaluate existing requirements and consider proposals for changes.

TXU Corp. continues to closely monitor any potential legislative changes pertaining to climate change and CO₂ emissions. The increasing attention to potential environmental effects of greenhouse gas emissions creates risk as to the completion of TXU Corp.'s plan to develop new coal-fueled generation facilities in Texas. New legislation could result in higher costs due to new taxes, the need to acquire emissions credits or capital spending to reduce CO₂ emissions. TXU Corp. believes that any legislative actions to reduce greenhouse gas emissions should be developed under a market-based framework that is consistent with expected technology development timelines and supports the displacement of old, inefficient electricity generation technology with advanced, more efficient and cleaner-emitting technology.

As discussed above, TXU Corp. has announced actions to address CO₂ emissions concerns, including:

- Establishing a plan to invest up to \$2 billion for the development and commercialization of cleaner generation plant technologies;
- Initiating the process to file an application to the NRC for licenses to construct and operate a new nuclear generation facility in Texas;
- Doubling the renewable energy (wind generation) portfolio to 1,500 MW;
- Investing up to \$400 million in programs designed to encourage customer electricity demand efficiencies; and
- Increasing production efficiency of its existing generation facilities by up to 2 percent.

Cost Exposure Related to Nuclear Asset Outages

TXU Corp.'s nuclear assets are comprised of two generating units at Comanche Peak, each with a capacity of 1,150 MW. The Comanche Peak plant represents approximately 13% of TXU Corp.'s total generation capacity. The nuclear generation facilities represent TXU Corp.'s lowest marginal cost source of electricity. Assuming both nuclear generating units experienced an outage, the unfavorable impact to pretax earnings is estimated to be approximately \$3.5 million per day before consideration of any insurance proceeds. Maintaining safe, reliable and efficient operations at the Comanche Peak plant is one of TXU Corp.'s top priorities. Also see discussion of nuclear facilities insurance in Note 16 to Financial Statements.

APPLICATION OF CRITICAL ACCOUNTING POLICIES

TXU Corp.'s significant accounting policies are discussed in Note 1 to Financial Statements. TXU Corp. follows accounting principles generally accepted in the US. Application of these accounting policies in the preparation of TXU Corp.'s consolidated financial statements requires management to make estimates and assumptions about future events that affect the reporting of assets and liabilities at the balance sheet dates and revenue and expense during the periods covered. The following is a summary of certain critical accounting policies of TXU Corp. that are impacted by judgments and uncertainties and under which different amounts might be reported using different assumptions or estimation methodologies.

Derivative Instruments and Mark-to-Market Accounting — TXU Corp. enters into contracts for the purchase and sale of energy-related commodities, and also enters into other derivative instruments such as options, swaps, futures and forwards primarily to manage commodity price and interest rate risks. Under SFAS 133, these instruments are subject to mark-to-market accounting, and the determination of market values for these instruments is based on numerous assumptions and estimation techniques.

Mark-to-market accounting recognizes changes in the fair value of derivative instruments in the financial statements as market prices change. The availability of quoted market prices in energy markets is dependent on the type of commodity (e.g., natural gas, electricity, etc.), time period specified and delivery point. In computing the mark-to-market valuations, each market segment is separated into liquid and illiquid periods. The liquid period varies by delivery point and commodity. Generally, the liquid period is supported by broker quotes and frequent trading activity. For illiquid periods, fair value is estimated based on forward price curves developed using market modeling techniques that take into account available market information; TXU Corp. generally recognizes losses but not gains due to the modeling risks associated with illiquid periods.

SFAS 133 allows for “normal” purchase or sale elections and hedge accounting designations, which generally eliminates or defers the requirement for mark-to-market recognition in net income and thus reduces the volatility of net income that can result from fluctuations in fair values. These elections and designations are intended to better match the accounting recognition of financial performance with the economic and risk decision-making profile. “Normal” purchases and sales are contracts that provide for physical delivery of quantities expected to be used or sold over a reasonable period in the normal course of business. Derivative contracts held for trading purposes are marked-to-market in net income.

In accounting for cash flow hedges, changes in fair value are recorded in other comprehensive income to the extent the change in value is effective; that is, it mirrors the offsetting change in fair value of the forecasted hedged transaction. Changes in value that represent ineffectiveness of the hedge are recognized in net income immediately, and the effective portion of changes in fair value are initially recorded in other comprehensive income and are recognized in net income when the hedged transactions are recognized. Because TXU Corp.'s generation position is not marked-to-market, management has striven to make elections under SFAS 133 with respect to economic hedges of that position that allow accounting results to be more reflective of the economic position. TXU Corp. continually assesses these elections and under SFAS 133 could dedesignate positions currently accounted for as cash flow hedges, the effect of which could be more volatility of reported earnings as all changes in the fair value of the positions would be included in net income. Also see discussions of the long-term hedging program discussed above under “TXU Energy Holdings Segment Significant Developments.”

The following tables provide the effects on both net income and other comprehensive income of accounting for those derivative instruments that TXU Corp. has determined to be subject to fair value measurement under SFAS 133:

	<u>Year Ended December 31,</u>		
	<u>2006</u>	<u>2005</u>	<u>2004</u>
Amounts recognized in net income (after-tax):			
Unrealized ineffectiveness net gains (losses) on unsettled positions accounted for as cash flow hedges	\$ 141	\$ (24)	\$ (14)
Reversals of previously recognized unrealized net losses related to cash flow hedge positions settled in the period	14	7	1
Unrealized net gains (losses) on unsettled positions marked-to-market in net income	15	21	(19)
Reversals of previously recognized unrealized net losses (gains) related to marked-to-market positions settled in the period.....	7	(15)	(40)
Total.....	<u>\$ 177</u>	<u>\$ (11)</u>	<u>\$ (72)</u>
Amounts recognized in other comprehensive income (after-tax):			
Net gains (losses) in fair value of unsettled positions accounted for as cash flow hedges.....	\$ 568	\$ (47)	\$ (75)
Net losses (gains) on cash flow hedge positions recognized in net income to offset hedged transactions.....	(15)	77	44
Total.....	<u>\$ 553</u>	<u>\$ 30</u>	<u>\$ (31)</u>

The effect of mark-to-market and hedge accounting on the balance sheet is as follows:

	<u>December 31,</u>	
	<u>2006</u>	<u>2005</u>
Net derivative asset (liability) related to cash flow hedges	\$ 910	\$ (164)
Net derivative liability related to interest rate fair value hedges	(85)	(71)
Other derivative assets.....	9	9
Total net cash flow hedge and other derivative asset (liability).....	<u>\$ 834</u>	<u>\$ (226)</u>
Net commodity contract asset (a).....	<u>\$ 69</u>	<u>\$ 36</u>
Long-term debt fair value adjustments —decrease in carrying value (b).....	<u>\$ (63)</u>	<u>\$ (44)</u>
Net accumulated other comprehensive gain (loss) included in shareholders' equity (after-tax amounts).....	<u>\$ 411</u>	<u>\$ (142)</u>

- (a) Excludes amounts not arising from mark-to-market valuations such as payments and receipts of cash and other consideration associated with commodity hedging and trading activities.
- (b) Includes unamortized net gains of \$6 million in 2006 related to settled interest rate swaps designated as fair value hedges. The gain is being amortized to net income as the hedged transactions are recognized.

See discussion above under “TXU Energy Holdings Segment Significant Developments” regarding the long-term hedging program. A significant portion of the positions entered into under this program, which are natural gas-related financial instruments, are accounted for as cash flow hedges of future electricity sales.

Revenue Recognition — TXU Corp.'s revenue includes an estimate for unbilled revenue that represents estimated daily kilowatt-hours (kWh) consumption after the meter read date to the end of the period multiplied by the applicable billing rates. Estimated daily kWh usage is derived using historical kWh usage information adjusted for weather and other measurable factors affecting consumption. Calculations of unbilled revenues during certain interim periods are generally subject to more estimation variability because of seasonal changes in demand. Accrued unbilled revenues totaled \$466 million, \$494 million and \$422 million at December 31, 2006, 2005 and 2004, respectively.

Accounting for Contingencies — The financial results of TXU Corp. may be affected by judgments and estimates related to loss contingencies. A significant contingency that TXU Corp. accounts for is the loss associated with uncollectible trade accounts receivable. The determination of such bad debt expense is based on factors such as historical write-off experience, aging of accounts receivable balances, changes in operating practices, regulatory rulings, general economic conditions and customers' behaviors. Increased customer attrition due to competitive activity and seasonal variations in amounts billed adds to the complexity of the estimation process. Historical results alone are not always indicative of future results causing management to consider potential changes in customer behavior and make judgments about the collectibility of accounts receivable. Bad debt expense totaled \$68 million, \$56 million and \$90 million for the years ended December 31, 2006, 2005 and 2004, respectively.

Litigation contingencies also may require significant judgment in estimating amounts to accrue. During 2004, management assessed the progress and status of matters in litigation and recorded a net \$84 million (\$55 million after-tax) charge for the anticipated settlement of the shareholders' litigation initially filed in October 2002 (estimated litigation liability of \$150 million less \$66 million in pledged reimbursements from insurance carriers). In January 2005, TXU Corp. reached a comprehensive settlement of the shareholders' litigation, which included a one-time payment to the class members of \$150 million. To recognize additional insurance reimbursements related to the settlement, TXU Corp. recorded credits to earnings in 2005 and 2006 of \$35 million (\$23 million after-tax) and \$15 million (\$10 million after-tax), respectively.

Accounting for Income Taxes — TXU Corp.'s income tax expense and related balance sheet amounts involve significant management estimates and judgments. Amounts of deferred income tax assets and liabilities, as well as current and noncurrent accruals, involve judgments and estimates of the timing and probability of recognition of income and deductions by taxing authorities. In assessing the likelihood of realization of deferred tax assets, management considers estimates of the amount and character of future taxable income. Actual income taxes could vary from estimated amounts due to the future impacts of various items, including changes in income tax laws, TXU Corp.'s forecasted financial condition and results of operations in future periods, as well as final review of filed tax returns by taxing authorities. TXU Corp.'s income tax returns are regularly subject to examination by applicable tax authorities. In management's opinion, an adequate reserve has been made for any future taxes that may be owed as a result of any examination.

FIN 48 provides interpretive guidance for accounting for uncertain tax positions, and as discussed in Note 1 to the Financial Statements, TXU Corp. will adopt this new standard January 1, 2007, as required. Also, see Notes 11 and 16 to Financial Statements for discussion of income tax matters.

Impairment of Long-Lived Assets — TXU Corp. evaluates long-lived assets for impairment whenever indications of impairment exist, in accordance with SFAS 144. One of those indications is a current expectation that “more likely than not” a long-lived asset will be sold or otherwise disposed of significantly before the end of its previously estimated useful life. For TXU Corp.’s baseload generation assets, another possible indication would be an expected long-term decline in natural gas prices. The determination of the existence of these and other indications of impairment involves judgments that are subjective in nature and may require the use of estimates in forecasting future results and cash flows related to an asset or group of assets. Further, the unique nature of TXU Corp.’s property, plant and equipment, which includes a fleet of generation assets with a diverse fuel mix and individual plants that have varying production or output rates, requires the use of significant judgments in determining the existence of impairment indications and the grouping of assets for impairment testing.

In the second quarter of 2006, TXU Corp. recorded an impairment charge of \$198 million (\$129 million after-tax) related to its natural gas-fueled generation plants. See Note 6 to Financial Statements for a discussion of the impairment. The estimated impairment was based on numerous assumptions including forecasted production, forward prices of natural gas and electricity, overall generation availability in ERCOT, ERCOT grid congestion and forward heat rates. Because of the highly judgmental nature of key assumptions and potential volatility of market conditions, the adjusted carrying value of the plants does not necessarily represent the amount of proceeds from any transaction to sell the assets, and future additional impairment is possible.

TXU Corp.’s most significant long-lived asset in terms of carrying value is its Comanche Peak nuclear generation facility. The net book value of the facility was \$7.4 billion at December 31, 2006. TXU Corp. believes that the net book value of the facility significantly exceeds the estimated current market value. However, in applying the provision of SFAS 144, TXU Corp. estimates that future undiscounted cash flows from the facility significantly exceed net book value. Significant assumptions used in this analysis are forward price curves for natural gas and electricity, market heat rates and production estimates. TXU Corp. has conservatively estimated that a sustained structural decline in natural gas prices of at least 60% from current levels would need to occur before any risk of impairment of the facility would arise, assuming market heat rates remain unchanged.

Depreciation — The depreciable lives of property, plant and equipment are based on management’s estimates/determinations of the assets’ economical useful lives. To the extent that the actual lives differ from these estimates, the amount of period depreciation charges to earnings would be impacted. Consolidated depreciation expense as a percent of average depreciable property carrying value approximated 2.3% for 2006, 2005 and 2004.

Effective January 1, 2005, the estimated depreciable lives of lignite/coal-fueled generation facilities were extended from fifty years to sixty years to better reflect their useful lives.

Effective January 1, 2004, the estimated depreciable lives of lignite/coal-fueled generation facilities were extended an average of nine years to better reflect the useful lives of the assets, and depreciation rates for the Comanche Peak nuclear generating facility were decreased as a result of an increase in the estimated lives of boiler and turbine generator components of the facility by an average of five years.

Regulatory Assets — The financial statements at December 31, 2006 and 2005, reflect total regulatory assets of \$2.2 billion and \$1.9 billion, respectively. These amounts include \$1.3 billion and \$1.5 billion, respectively, of generation-related regulatory assets recoverable by securitization (transition) bonds as discussed immediately below. Rate regulation is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs, the rate earned on invested capital and the timing and amount of assets to be recovered by rates. (See disclosures in Note 25 to Financial Statements under “Regulatory Assets and Liabilities.”)

Regulatory asset stranded costs arising prior to the 1999 Restructuring Legislation became subject to recovery through issuance of \$1.3 billion principal amount of transition bonds by TXU Electric Delivery in accordance with a regulatory financing order (see Note 4 to Financial Statements). As adjusted, the carrying value of the regulatory asset upon final issuance of the bonds in 2004 represented the projected future cash flows to be recovered from REPs by TXU Electric Delivery through revenues as a transition charge to service the principal and fixed rate interest on the bonds. The regulatory asset is being amortized to expense in an amount equal to the transition charge revenues being recognized.

Other regulatory assets that TXU Corp. believes are probable of recovery, but are subject to review and possible disallowance in a future regulatory rate case, totaled \$655 million at December 31, 2006. These amounts consist primarily of employee retirement costs (see Note 21 to Financial Statements) and storm-related service recovery costs.

Defined Benefit Pension Plans and Other Postretirement Employee Benefit Plans — TXU Corp. offers pension benefits through either a defined benefit pension plan or a cash balance plan and also offers certain health care and life insurance benefits to eligible employees and their eligible dependents upon the retirement of such employees from TXU Corp. Reported costs of providing noncontributory defined pension benefits and other postretirement employee benefits (OPEB) are dependent upon numerous factors, assumptions and estimates.

Benefit costs are impacted by actual employee demographics (including but not limited to age, compensation levels and years of accredited service), the level of contributions made to retiree plans, expected and actual earnings on plan assets and the discount rates used in determining the projected benefit obligation. Changes made to the provisions of the plans may also impact current and future benefit costs. Fluctuations in actual equity market returns as well as changes in general interest rates may result in increased or decreased benefit costs in future periods.

In accordance with accounting rules, changes in benefit obligations associated with these factors may not be immediately recognized as costs in the income statement, but are recognized in future years over the remaining average service period of plan participants. As such, significant portions of benefit costs recorded in any period may not reflect the actual level of cash benefits provided to plan participants. Pension and OPEB costs as determined under applicable accounting rules are summarized in the following table:

	Year Ended December 31,		
	<u>2006</u>	<u>2005</u>	<u>2004</u>
Pension costs under SFAS 87.....	\$ 66	\$ 46	\$ 58
OPEB costs under SFAS 106.....	81	71	80
Total benefit costs.....	\$ 147	\$ 117	\$ 138
Less amounts deferred principally as a regulatory asset or property.....	(84)	(58)	(27)
Net amounts recognized as expense.....	<u>\$ 63</u>	<u>\$ 59</u>	<u>\$ 111</u>

Detailed information regarding TXU Corp.'s pension and OPEB costs is provided in Note 21 to Financial Statements. Additional information regarding pension and OPEB plans:

- Pension and OPEB costs increased \$30 million to \$147 million in 2006 primarily due to a lower discount rate (5.75% in 2006 versus 6.00% in 2005) used to measure pension and OPEB obligations.
- Pension and OPEB costs decreased \$21 million to \$117 million in 2005 due primarily to fewer active employees following the 2004 Capgemini outsourcing and TXU Gas disposition transactions and other 2004 restructuring actions. (See Note 8 to Financial Statements.)
- A curtailment charge of \$5 million is included in pension and OPEB costs in 2004 due to the effects of the Capgemini outsourcing and TXU Gas disposition transactions.

In 2006, the assumed discount rate for both the pension and OPEB obligations was 5.75%. The expected rate of return on assets was 8.75% for the pension plan and 8.67% for the OPEB plan.

Sensitivity of these costs to changes in key assumptions is as follows:

<u>Assumption</u>	<u>Increase/(decrease) in 2006 Pension and OPEB Costs</u>
Discount rate – 1% increase.....	\$(42)
Discount rate – 1% decrease.....	\$ 37
Expected return on assets – 1% increase.....	\$(19)
Expected return on assets – 1% decrease.....	\$ 19

Regulatory Recovery of Pension and OPEB Costs — In June 2005, an amendment to PURA relating to pension and OPEB costs was enacted by the Legislature of the State of Texas. This amendment provides for the recovery by TXU Electric Delivery of pension and OPEB costs for all applicable former employees of the regulated predecessor integrated electric utility, which in addition to its own employees consists largely of active and retired personnel engaged in TXU Energy Company's activities, related to service of those additional personnel prior to the deregulation and disaggregation of TXU Corp.'s business effective January 1, 2002. The amendment additionally authorizes TXU Electric Delivery to establish a regulatory asset or liability for the difference between the amounts of pension and OPEB costs approved in current billing rates and the actual amounts that would otherwise have been recorded as charges or credits to earnings. Accordingly, in the second quarter of 2005, TXU Electric Delivery began deferring (principally as a regulatory asset or property) additional pension and OPEB costs for the effect of the amendment, which was retroactively effective January 1, 2005. Amounts deferred are ultimately subject to regulatory approval.

Stock-Based Incentive Compensation – Under its shareholder-approved long-term incentive plans, TXU Corp. has provided discretionary awards to qualified management employees in the form of restricted stock and performance units payable in common stock upon vesting. The awards generally vest over a three-year period and the number of shares ultimately earned is based on the performance of TXU Corp.’s stock over the vesting period as compared to the stock price performance of a peer group of companies (index method) or as compared to a combination of the index method and established thresholds of TXU Corp. stock performance. Stock-based compensation expense, which is reported in selling, general and administrative (SG&A) expenses, totaled \$27 million, \$32 million and \$56 million in 2006, 2005 and 2004, respectively. The expense is determined based on the grant date fair value of the awards amortized over the vesting period in accordance with SFAS 123(R). See Note 22 to Financial Statements for additional information.

The determination of the fair value of stock-based compensation awards at grant date is based on a Monte Carlo simulation. The more significant assumptions used in this valuation process are as follows:

- Expected volatility of the stock price of TXU Corp. and peer group companies – expected volatility is determined based on historical stock price volatilities using daily stock price returns for the three years prior to the grant date.
- The dividend rate for TXU Corp. and peer group companies based on the observed dividend payments over the twelve months prior to grant date.
- Risk-free rate during the three year vesting period – the rate used for the April 1, 2006 awards was the interest rate at that date for three-year U.S. Treasury securities, which was 4.83%.
- Discount for liquidation restrictions – this factor estimates the discount for lack of marketability of vested awards due to the anticipated time for the approval and issuance of the awards, the black-out period immediately after the grant and additional holding requirements imposed on senior executives. This discount is determined based on an estimation of the cost of a protective put at the award date and is calculated using the Black-Scholes option pricing model using expected volatility assumptions based on historical and implied volatility as discussed above and a risk-free rate of return over the option period.

The sensitivity effects of reasonable changes in key assumptions were not significant to the fair value of the 2006 awards.

RESULTS OF OPERATIONS

Results of operations and the related management's discussion of those results for all periods presented reflect the discontinuance of certain operations (see Note 3 to Financial Statements regarding discontinued operations).

In the first quarter of 2007, TXU Corp. expects to write-off approximately \$60 million (\$39 million after-tax) in deferred costs related to previously anticipated transactions that are no longer expected to be completed as a result of the Merger Agreement announced on February 26, 2007. TXU Corp. also expects to record charges in the first quarter of 2007 related to the suspended development of eight coal-fueled generation units, but the amounts are currently not estimable.

In the first quarter of 2007, TXU Corp. expects to record a "day one" loss of approximately \$70 million (\$46 million after-tax) associated with a related series of hedging transactions in February 2007. See discussion above under "TXU Energy Holdings Segment Significant Developments".

TXU Corp. Consolidated

2006 compared to 2005

Reference is made to comparisons of results by business segment following the discussion of consolidated results. The business segment comparisons provide additional detail and quantification of items affecting financial results.

TXU Corp.'s operating revenues increased \$194 million, or 2%, to \$10.9 billion in 2006 as shown in the table below:

	Year Ended December 31,		Increase (Decrease)
	2006	2005	
TXU Energy Holdings segment:			
Retail electricity revenues	\$ 6,953	\$ 6,330	\$ 623
Accrued customer appreciation bonus	(162)	—	(162)
Wholesale electricity revenues	2,278	2,807	(529)
Wholesale balancing activities	(31)	225	(256)
Results of risk management and trading activities	153	(164)	317
Other operating revenues	358	354	4
Total TXU Energy Holdings segment	9,549	9,552	(3)
TXU Electric Delivery segment	2,449	2,394	55
Net intercompany eliminations	(1,142)	(1,284)	142
Total consolidated revenues	<u>\$10,856</u>	<u>\$10,662</u>	<u>\$ 194</u>

The following discusses the changes in revenue within the TXU Energy Holdings segment:

- A 10% increase in retail electricity revenues was driven by higher pricing, partially offset by the effect of an 11% decline in retail sales volumes. Higher retail prices reflected increases in natural gas prices that resulted in the regulatory-approved price-to-beat rate increases implemented in May 2005, October 2005 and January 2006. The decline in retail sales volumes reflected a net loss of customers due to competitive activity and lower average consumption per residential and small business customer.
- A \$162 million (\$105 million after-tax) charge was recorded in the fourth quarter of 2006 for a special residential customer appreciation bonus. See discussion in Note 7 to Financial Statements for details.
- The decline in wholesale electricity revenues reflected the reporting of wholesale electricity trading activity on a net basis in 2006 as described in Note 1 to Financial Statements.
- Wholesale balancing net revenues/purchases are subject to high variability as the activity represents intraday purchases and sales transactions with ERCOT for real-time balancing purposes as measured in 15-minute intervals. See Note 1 to Financial Statements for a discussion regarding reporting of ERCOT balancing activities.
- The gains arising from risk management and trading activities in 2006 primarily reflect the unrealized effects of changes in natural gas prices and market heat rates on positions in the long-term hedging program implemented in the fourth quarter of 2005, while the losses in 2005 primarily represent realized losses on prior years' hedging activities.

The 2% revenue increase in the TXU Electric Delivery segment reflected higher transmission and distribution tariffs as well as growth in points of delivery.

The decline in net intercompany sales elimination reflected lower sales by TXU Electric Delivery to REP subsidiaries of TXU Energy Company, while its sales to nonaffiliated REPs increased.

Gross Margin

	Year Ended December 31,			
	2006	% of Revenue	2005	% of Revenue
Operating revenues	\$ 10,856	100%	\$ 10,662	100%
Costs and expenses:				
Fuel, purchased power costs and delivery fees ...	2,784	26	4,261	40
Operating costs	1,373	13	1,425	13
Depreciation and amortization	<u>813</u>	<u>7</u>	<u>764</u>	<u>7</u>
Gross margin	<u>\$ 5,886</u>	<u>54%</u>	<u>\$ 4,212</u>	<u>40%</u>

Gross margin is considered a key operating metric as its changes measure the effect of movements in sales volumes and pricing versus the variable and fixed costs to generate, purchase and deliver electricity.

Gross margin increased \$1.7 billion, or 40%, to \$5.9 billion in 2006.

- The TXU Energy Holdings segment's gross margin increased \$1.7 billion, or 55%, to \$4.7 billion. The gross margin increase reflected the regulatory-approved price-to-beat increases and unrealized net gains from cash flow hedge ineffectiveness and mark-to-market valuations of positions in the long-term hedging program.
- The TXU Electric Delivery segment's gross margin increased \$15 million, or 1%, to \$1.2 billion in 2006, driven by higher revenues.

Fuel, purchased power costs and delivery fees declined \$1.5 billion, or 35%, to \$2.8 billion primarily due to the reporting of wholesale trading activity on a net basis in 2006 as discussed in Note 1 to the Financial Statements.

Operating costs decreased \$52 million, or 4%, to \$1.4 billion in 2006.

- TXU Energy Holdings' operating costs decreased \$64 million, or 10%, primarily reflecting lower maintenance costs due to both nuclear generation units having scheduled refueling outages in 2005 compared to one in 2006, as well as lower incentive compensation expense in 2006 and the absence of combustion turbine lease expense in 2006 resulting from the purchase of a lease trust interest in early 2006 (see Note 4 to Financial Statements).
- TXU Electric Delivery's operating costs increased \$12 million, or 2%, driven by fees paid to third-party transmission entities.

Depreciation and amortization (consisting almost entirely of amounts related to generation plants and the delivery system shown in the gross margin table above) increased \$54 million, or 7%, to \$830 million in 2006. The increased expense reflects depreciation related to normal additions and replacements of property and higher expense associated with mining land reclamation activities.

SG&A expenses increased \$38 million, or 5%, to \$819 million in 2006. The increase reflected:

- \$39 million in costs associated with the new generation development programs, principally salaries and consulting expenses;
- \$17 million in higher fees related to the sale of accounts receivable program due to higher interest rates;
- \$12 million in executive severance costs; and
- \$12 million in higher bad debt expense primarily reflecting higher retail accounts receivable balances due to higher prices,

partially offset by:

- \$20 million in lower stock-based incentive compensation expense due primarily to fewer share awards and lower expense related to a deferred compensation plan;
- \$9 million in lower consulting fees related to various strategic initiatives, including fees in 2005 relating to the TXU Operating System; and
- \$7 million in lower compensation expense resulting from cost reduction initiatives.

Franchise and revenue-based taxes increased \$26 million, or 7%, to \$390 million reflecting higher state gross receipts taxes due to higher revenues and higher city franchise tax assessments under the TXU Electric Delivery cities rate settlement. See Note 9 to Financial Statements.

Other income totaled \$121 million in 2006 and \$151 million in 2005. Other deductions totaled \$269 million in 2006, which included a \$198 million impairment charge related to natural gas-fueled generation plants, and \$45 million in 2005. See Note 12 to Financial Statements for detail of other income and deductions.

Interest expense and related charges increased \$28 million, or 3%, to \$830 million in 2006. The increase reflected \$69 million from higher average interest rates (including the effect of interest rate swap transactions), partially offset by \$30 million in increased capitalized interest and \$11 million due to lower average borrowings.

Income tax expense from continuing operations totaled \$1.3 billion in 2006 compared to \$632 million in 2005. The effective tax rate was 33.9% in 2006 compared to 26.3% in 2005. The 2006 amount included a charge of \$44 million (1.2 percentage point effective tax rate impact) representing an adjustment to net deferred tax liabilities arising from the enactment of the Texas margin tax as described in Note 10 to the Financial Statements. The 2005 amount included \$138 million in additional tax benefit (5.7 percentage point effective tax rate impact) related to the TXU Europe write-off as described in Note 11 to the Financial Statements and \$29 million benefit (1.2 percentage point effective tax rate impact) related to the release of a tax reserve.

Income from continuing operations (an after-tax measure) increased \$690 million, or 39%, to \$2.5 billion in 2006.

- Earnings in the TXU Energy Holdings segment increased \$934 million, or 65%, to \$2.4 billion driven primarily by improved gross margin partially offset by a charge for the write-down of the natural gas-fueled generation plants.
- Earnings in the TXU Electric Delivery segment decreased \$7 million, or 2%, to \$344 million driven by expenses in 2006 related to the cities rate settlement and the InfrastruX Energy Services joint venture.
- Corporate and Other net expenses totaled \$242 million in 2006 and \$5 million in 2005. The increase reflected (all amounts after-tax):
 - a \$138 million tax benefit in 2005 related to TXU Europe (see Note 11 to Financial Statements);
 - an \$85 million increase (to \$241 million) in net interest expense related to advances from subsidiaries reflecting higher balances and interest rates;
 - a \$17 million gain in 2006 related to a settlement of a telecommunications contract dispute; and
 - \$10 million and \$23 million of insurance recoveries in 2006 and 2005, respectively, related to the 2005 shareholders' litigation settlement.

Net pension and other postretirement employee benefit costs reduced income from continuing operations by \$41 million in 2006 and \$38 million in 2005. See Note 21 to Financial Statements.

Income from discontinued operations (an after-tax measure) totaled \$87 million in 2006 and \$5 million in 2005. See Note 3 to Financial Statements for details.

Diluted earnings per share of common stock totaled \$5.46 in 2006 and \$2.50 in 2005.

- Diluted earnings per share in 2006 reflected a favorable \$0.16 per share impact from the repurchase of approximately 18.5 million shares since December 31, 2005. Basic average common shares outstanding decreased 3% to 460 million shares reflecting these share repurchases. Diluted average common shares decreased 4% to 467 million shares. (See Note 2 to Financial Statements.)
- Diluted earnings per share in 2005 reflect an unfavorable impact associated with the November 2004 accelerated share repurchase program. See Notes 2 and 17 to Financial Statements.

TXU Corp. Consolidated

2005 compared to 2004

Reference is made to comparisons of results by business segment following the discussion of consolidated results. The business segment comparisons provide additional detail and quantification of items affecting financial results.

TXU Corp.'s operating revenues increased \$1.4 billion, or 16%, to \$10.7 billion in 2005.

- Operating revenues in the TXU Energy Holdings segment increased \$1.2 billion, or 14%, to \$9.6 billion driven by higher retail and wholesale pricing, which was primarily the result of higher natural gas prices. The effect of higher pricing was partially offset by the effect of lower retail sales volumes. Retail sales volumes declined 17% primarily reflecting a net loss of customers to competitive activity, particularly in the large business market, partially offset by the effect of warmer weather.
- Operating revenues in the TXU Electric Delivery segment increased \$168 million, or 8%, to \$2.4 billion in 2005. The revenue increase was driven by a 5% increase in delivered volumes, due largely to warmer weather and an increase in delivery points. The balance of the growth reflected \$46 million in higher transition charges associated with securitization bonds issued in 2004 (offset in total by higher amortization of the related regulatory asset as discussed below). Additionally, higher transmission and distribution tariffs driven by TXU Electric Delivery's ongoing transmission investment program and market growth contributed to increased revenues.
- Consolidated revenue growth reflected a \$128 million reduction in the intercompany sales elimination, primarily reflecting lower sales by TXU Electric Delivery to TXU Energy Holdings, while its sales to nonaffiliated REPs increased.

Gross Margin

	Year Ended December 31,			
	2005	% of Revenue	2004	% of Revenue
Operating revenues	\$10,662	100%	\$ 9,216	100%
Costs and expenses:				
Fuel, purchased power costs and delivery fees ...	4,261	40%	3,755	41%
Operating costs	1,425	13%	1,429	15%
Depreciation and amortization	<u>764</u>	<u>7%</u>	<u>709</u>	<u>8%</u>
Gross margin	<u>\$ 4,212</u>	<u>40%</u>	<u>\$ 3,323</u>	<u>36%</u>

Gross margin increased \$889 million, or 27%, to \$4.2 billion in 2005.

- The TXU Energy Holdings segment's gross margin increased \$831 million, or 38%, to \$3.0 billion, driven by higher pricing partially offset by higher per MWh cost of purchased power and gas-fueled generation as well as the effect of lower sales volumes.
- The TXU Electric Delivery segment's gross margin increased \$80 million, or 7%, to \$1.2 billion in 2005, driven by higher operating revenues.

Operating costs were \$1.4 billion in both 2005 and 2004.

- TXU Energy Holdings' operating costs declined \$35 million, or 5%. As discussed below in the business segment analysis, this decline was due to a number of factors, including the absence of \$43 million of costs related to activities no longer performed.
- TXU Electric Delivery's operating costs rose \$28 million, or 4%, driven by increased spending for reliability initiatives and higher property taxes due to increased investments in property.

Depreciation and amortization (consisting almost entirely of amounts related to generation plants and the delivery system shown in the gross margin table above) increased \$16 million, or 2%, to \$776 million in 2005. The increase included higher amortization of the regulatory asset associated with securitization bonds (offset in revenues) and higher depreciation due to normal additions of property, largely offset by a change in the carrying value of software assets in connection with the Capgemini outsourcing transaction and the effect of reduced 2005 depreciation rates for lignite/coal-fueled plants due to extending the estimated useful lives.

SG&A expense decreased \$310 million, or 28%, to \$781 million in 2005. The decline reflected:

- \$93 million resulting from cost reduction initiatives including the Capgemini outsourcing agreement;
- \$52 million in nonrecurring executive compensation costs in 2004;
- \$50 million in reduced incentive compensation expense including \$15 million due to a one-time incentive compensation program in wholesale operations in 2004;
- \$42 million in consulting and professional fees in 2004 related to the formulation and execution of strategic initiatives;
- \$34 million in lower bad debt expense as a result of stricter disconnect policies and more focused collection activities; and
- \$15 million in reduced pension and other postretirement benefits primarily due to the effect of Texas legislation enacted in the second quarter of 2005. (See Note 21 to Financial Statements.)

Other income totaled \$151 million in 2005 and \$148 million in 2004. Other deductions totaled \$45 million in 2005 and \$1.2 billion in 2004. The other deductions in 2004 primarily represented charges related to the restructuring actions discussed in Note 8 to Financial Statements. Also see Note 12 to Financial Statements for detail of other income and deductions.

Interest income increased \$20 million to \$48 million in 2005 primarily reflecting losses on interest rate swaps in 2004 (related to a note receivable) and higher interest earned on short-term investments in 2005.

Interest expense and related charges increased \$107 million, or 15%, to \$802 million in 2005 reflecting \$66 million due to higher average borrowings and \$41 million due to higher average interest rates.

Income tax expense on income from continuing operations before extraordinary gain (loss) and cumulative effect of changes in accounting principles included:

- \$138 million in additional tax benefit recorded in the first quarter of 2005 related to the TXU Europe write-off. This benefit reflects identification of tax planning strategies TXU Corp. would implement to ensure utilization of capital losses associated with the write-off of the investment in TXU Europe; and
- \$75 million tax benefit recorded in the second quarter of 2004 arising from the sale of TXU Fuel Company (TXU Fuel).

The effective income tax rate excluding the effect of these benefits was 32.0% in 2005 and 95.1% in 2004. The 2005 effective income tax rate reflects a \$29 million benefit for the reversal of previously established tax reserves due to current period events. The 2004 effective rate reflected the limited deductibility of expenses recorded in connection with the repurchase of convertible and equity-linked debt securities on a small income base.

Income from continuing operations before extraordinary items and the cumulative effect of changes in accounting principle (an after-tax measure) increased to \$1.8 billion in 2005 from \$81 million in 2004.

- Earnings in the TXU Energy Holdings segment increased \$1.0 billion to \$1.4 billion driven by improved gross margin, the effect of restructuring-related charges in 2004 and lower SG&A expenses.
- Earnings in the TXU Electric Delivery segment increased \$96 million, or 38%, to \$351 million driven by higher operating revenues and the impact of 2004 restructuring-related charges and a rate case settlement charge (see Note 8 to Financial Statements).
- Corporate and other activities resulted in net expenses of \$5 million in 2005 compared to \$582 million in 2004. The improvement of \$577 million reflected (all amounts after-tax):
 - \$382 million of debt extinguishment losses due primarily to restructuring-related actions in 2004;
 - \$138 million income tax benefit recorded in 2005 related to TXU Europe;
 - \$56 million for a litigation accrual in 2004;
 - \$52 million pre and after-tax in nonrecurring executive compensation in 2004;
 - \$27 million in restructuring-related consulting and professional fees in 2004; and
 - \$23 million insurance recovery in 2005 related to the 2005 shareholders litigation settlement,partially offset by the recognition in 2004 of a \$75 million income tax benefit arising from the sale of TXU Fuel.

Net pension and postretirement benefit costs reduced income from continuing operations by \$38 million in 2005 and \$64 million in 2004. See Note 21 to Financial Statements.

Income from discontinued operations (an after-tax measure) totaled \$5 million in 2005 and \$378 million in 2004. See Note 3 to Financial Statements for details.

Diluted results per share of common stock were net income of \$2.50 in 2005 compared to a net loss of \$0.64 in 2004.

- The 2005 diluted per share results reflect an unfavorable impact associated with the November 2004 accelerated share repurchase program. See Note 17 to Financial Statements.
- Diluted earnings per share in 2005 reflected the favorable impact of 114 million fewer average shares outstanding in 2005. Basic average common shares outstanding decreased 21% to 476 million shares reflecting the repurchase of 105 million shares in November 2004 under the accelerated share repurchase program and the repurchase of 12 million shares in 2005. (See Notes 2 and 17 to Financial Statements.) Diluted average common shares decreased 19% to 486 million shares.
- Per share results in 2004 were unfavorably impacted by TXU Corp.'s repurchase of TXU Energy Holdings' exchangeable preferred membership interests in April 2004 (see Notes 2 and 17 to Financial Statements). For 2004, results per diluted share of common stock equaled results per basic share because of antidilution accounting rules.

Energy-Related Commodity Contracts and Mark-to-Market Activities

The table below summarizes the changes in commodity contract assets and liabilities for the years ended December 31, 2006, 2005 and 2004. The net changes in these assets and liabilities, excluding “other activity” as described below, represent the net effect of mark-to-market accounting for positions in the commodity contract portfolio, which excludes positions that are subject to cash flow hedge accounting. For the 2006 period, this effect totaled \$33 million in unrealized net gains, which represented \$22 million in net gains on unsettled positions and \$11 million in reversals of net losses recognized in prior periods on positions settled in the current period. These positions represent both economic hedging and trading activities.

	December 31,		
	2006	2005	2004
Commodity contract net asset (liability) at beginning of period.....	\$ (56)	\$ 23	\$ 108
Settlements of positions included in the opening balance (1).....	11	(23)	(61)
Unrealized mark-to-market valuations of positions held at end of period (2).....	22	32	(29)
Other activity (3).....	—	(88)	5
Commodity contract net asset (liability) at end of period	<u>\$ (23)</u>	<u>\$ (56)</u>	<u>\$ 23</u>

- (1) Represents reversals of unrealized mark-to-market valuations of these positions recognized in net income prior to the beginning of the period, to offset gains and losses realized upon settlement of the positions in the current period.
- (2) Includes gains and losses recorded at contract inception dates. In June 2006, a subsidiary of TXU Corp. entered into a related series of commodity hedge transactions at below-market prices resulting in a \$109 million loss at inception date. See Note 18 to Financial Statements.
- (3) These amounts have not been recognized in prior and current year mark-to-market earnings. Includes initial values of positions involving the receipt or payment of cash or other consideration such as option premiums paid and received. Activity in 2005 included \$75 million of natural gas received related to physical swap transactions and a \$12 million charge related to nonperformance by a coal contract counterparty.

In addition to the net effect of recording unrealized mark-to-market gains and losses that are reflected in the table above, similar effects arise in the recording of unrealized ineffectiveness gains and losses associated with commodity-related cash flow hedges. These effects, which include reversals of previously recorded unrealized ineffectiveness gains and losses to offset realized gains and losses upon settlement, are reflected in the balance sheet as changes in cash flow hedge and other derivative assets and liabilities. The total net effect of recording unrealized gains and losses related to commodity contracts under SFAS 133 is summarized as follows:

	December 31,		
	2006	2005	2004
Unrealized gains/(losses) related to contracts marked-to-market	\$ 33	\$ 9	\$ (90)
Ineffectiveness gains/(losses) related to cash flow hedges (a).....	<u>239</u>	<u>(27)</u>	<u>(19)</u>
Total unrealized gains (losses) related to commodity contracts	<u>\$ 272</u>	<u>\$ (18)</u>	<u>\$ (109)</u>

(a) See Note 19 to Financial Statements.

These amounts are reported in the “risk management and trading activities” component of revenues.

Maturity Table — Included in the net commodity contract liability above at December 31, 2006, is a net asset of \$69 million representing cumulative unrealized mark-to-market net gains that have been recognized in current and prior years' earnings. More than offsetting this net asset is a net liability of \$92 million included in the December 31, 2006 balance sheet that is comprised principally of amounts representing current and prior years' net receipts of cash or other consideration, including \$86 million related to natural gas physical swap transactions. The following table presents the unrealized net commodity contract asset arising from mark-to-market accounting as of December 31, 2006, scheduled by contractual settlement dates of the underlying positions.

<u>Source of fair value</u>	Maturity dates of unrealized commodity contract net assets (liabilities) at December 31, 2006				
	Less than 1 year	1-3 years	4-5 years	Excess of 5 years	Total
Prices actively quoted.....	\$ (24)	\$ 6	\$33	\$ 4	\$ 19
Prices provided by other external sources(a).....	57	8	(64)	59	60
Prices based on models.....	(7)	(3)	—	—	(10)
Total.....	<u>\$ 26</u>	<u>\$ 11</u>	<u>\$ (31)</u>	<u>\$ 63</u>	<u>\$ 69</u>
Percentage of total fair value.....	38%	16%	(45)%	91%	100%

(a) Includes a “day one” loss of \$109 million associated with a related series of commodity hedge transactions. See Note 18 to Financial Statements.

The “prices actively quoted” category reflects only exchange traded contracts with active quotes available. The “prices provided by other external sources” category represents forward commodity positions at locations for which over-the-counter broker quotes are available. Over-the-counter quotes for power in ERCOT generally extend through 2010 and over-the-counter quotes for natural gas generally extend through 2015, depending upon delivery point. The “prices based on models” category contains the value of all nonexchange traded options, valued using option pricing models. In addition, this category contains other contractual arrangements which may have both forward and option components. In many instances, these contracts can be broken down into their component parts and each component valued separately. Components valued as forward commodity positions are included in the “prices provided by other external sources” category. Components valued as options are included in the “prices based on models” category.

TXU Energy Holdings Segment

Financial Results

	Year Ended December 31,		
	2006	2005	2004
Operating revenues	<u>\$ 9,549</u>	<u>\$ 9,552</u>	<u>\$ 8,402</u>
Costs and expenses:			
Fuel, purchased power costs and delivery fees	3,928	5,545	5,173
Operating costs.....	604	668	703
Depreciation and amortization.....	334	313	350
Selling, general and administrative expenses.....	571	522	666
Franchise and revenue-based taxes.....	126	114	117
Other income.....	(17)	(64)	(110)
Other deductions	215	15	611
Interest income.....	(202)	(70)	(31)
Interest expense and related charges	<u>388</u>	<u>393</u>	<u>353</u>
Total costs and expenses.....	<u>5,947</u>	<u>7,436</u>	<u>7,832</u>
Income from continuing operations before income taxes and cumulative effect of changes in accounting principles	3,602	2,116	570
Income tax expense.....	<u>1,239</u>	<u>687</u>	<u>162</u>
Income from continuing operations before cumulative effect of changes in accounting principles	<u>\$ 2,363</u>	<u>\$ 1,429</u>	<u>\$ 408</u>

TXU Energy Holdings Segment

Sales Volume Data

	<u>Year Ended December 31,</u>			<u>Change %</u>	<u>Change %</u>
	<u>2006</u>	<u>2005</u>	<u>2004</u>	<u>2006/2005</u>	<u>2005/2004</u>
Sales volumes:					
Retail electricity sales volumes – gigawatt hours (GWh):					
Historical service territory:					
Residential	25,932	29,239	30,897	(11.3)	(5.4)
Small business (a).....	<u>7,753</u>	<u>9,004</u>	<u>10,476</u>	<u>(13.9)</u>	<u>(14.1)</u>
Total historical service territory.....	33,685	38,243	41,373	(11.9)	(7.6)
Other territories:					
Residential	3,663	3,416	3,089	7.2	10.6
Small business (a).....	<u>671</u>	<u>674</u>	<u>363</u>	<u>(0.4)</u>	<u>85.7</u>
Total other territories	4,334	4,090	3,452	6.0	18.5
Large business and other customers.....	<u>14,031</u>	<u>15,843</u>	<u>25,466</u>	<u>(11.4)</u>	<u>(37.8)</u>
Total retail electricity.....	52,050	58,176	70,291	(10.5)	(17.2)
Wholesale electricity sales volumes.....	36,931	52,001	48,309	(29.0)	7.6
Net sales (purchases) of balancing electricity					
to/from ERCOT(b).....	<u>874</u>	<u>4,787</u>	<u>(1,613)</u>	<u>(81.7)</u>	<u>—</u>
Total sales volumes.....	<u>89,855</u>	<u>114,964</u>	<u>116,987</u>	<u>(21.8)</u>	<u>(1.7)</u>
Average volume (kWh) per retail customer (c):					
Residential	15,359	15,825	15,619	(2.9)	1.3
Small business	30,360	32,078	34,095	(5.4)	(5.9)
Large business and other customers.....	285,277	243,538	351,542	17.1	(30.7)
Weather (service territory average) – percent of normal (d):					
Percent of normal:					
Cooling degree days.....	117.6%	107.0%	90.0%		
Heating degree days.....	79.2%	90.0%	90.1%		

(a) Customers with demand of less than 1 MW annually.

(b) See Note 1 to Financial Statements for discussion of trading and ERCOT balancing activity in 2006.

(c) Calculated using average number of customers for period.

(d) Weather data is obtained from Weatherbank, Inc., an independent company that collects and archives weather data from reporting stations of the National Oceanic and Atmospheric Administration (a federal agency under the US Department of Commerce).

TXU Energy Holdings Segment

Customer Count Data

	<u>Year Ended December 31,</u>			<u>Change %</u>	<u>Change %</u>
	<u>2006</u>	<u>2005</u>	<u>2004</u>		
Customer counts:					
Retail electricity customers (end of period and in thousands) (a):					
Historical service territory:					
Residential.....	1,624	1,769	1,951	(8.2)	(9.3)
Small business (b).....	<u>258</u>	<u>281</u>	<u>309</u>	<u>(8.2)</u>	<u>(9.1)</u>
Total historical service territory	1,882	2,050	2,260	(8.2)	(9.3)
Other territories:					
Residential.....	247	213	194	16.0	9.8
Small business (b).....	<u>9</u>	<u>7</u>	<u>6</u>	<u>28.6</u>	<u>16.7</u>
Total other territories.....	256	220	200	16.4	10.0
Large business and other customers	<u>44</u>	<u>55</u>	<u>76</u>	<u>(20.0)</u>	<u>(27.6)</u>
Total retail electricity customers	<u>2,182</u>	<u>2,325</u>	<u>2,536</u>	<u>(6.2)</u>	<u>(8.3)</u>

(a) Based on number of meters.

(b) Customers with demand of less than 1 MW annually.

TXU Energy Holdings Segment

Revenue and Market Share Data

	<u>Year Ended December 31,</u>			<u>Change %</u>	<u>Change %</u>
	<u>2006</u>	<u>2005</u>	<u>2004</u>	<u>2006/2005</u>	<u>2005/2004</u>
Operating revenues:					
Retail electricity revenues:					
Historical service territory:					
Residential	\$ 3,804	\$ 3,444	\$ 3,164	10.5	8.8
Small business (a).....	<u>1,153</u>	<u>1,086</u>	<u>1,103</u>	<u>6.2</u>	<u>(1.5)</u>
Total historical service territory.....	4,957	4,530	4,267	9.4	6.2
Other territories:					
Residential	559	405	298	38.0	35.9
Small business (a).....	<u>80</u>	<u>65</u>	<u>34</u>	<u>23.1</u>	<u>91.2</u>
Total other territories	639	470	332	36.0	41.6
Large business and other customers.....	<u>1,357</u>	<u>1,330</u>	<u>1,771</u>	<u>2.0</u>	<u>(24.9)</u>
Total retail electricity revenues.....	6,953	6,330	6,370	9.8	(0.6)
Wholesale electricity revenues (b).....	2,278	2,807	1,886	(18.8)	48.8
Net sales (purchases) of balancing electricity					
to/from ERCOT (b)	(31)	225	(92)	—	—
Net gains (losses) from risk management and trading					
activities.....	153	(164)	(103)	—	(59.2)
Other operating revenues (c).....	<u>196</u>	<u>354</u>	<u>341</u>	<u>(44.6)</u>	<u>3.8</u>
Total operating revenues.....	<u>\$ 9,549</u>	<u>\$ 9,552</u>	<u>\$ 8,402</u>	<u>—</u>	<u>13.7</u>
Risk management and trading activities:					
Realized net gains (losses) on settled positions (d)	\$ (119)	\$ (146)	\$ 6		
Reversal of prior periods' unrealized net (gains)					
losses on positions settled in current period	32	(12)	(59)		
Other unrealized net gains (losses), including cash					
flow hedge ineffectiveness	<u>240</u>	<u>(6)</u>	<u>(50)</u>		
Total net gains (losses)	<u>\$ 153</u>	<u>\$ (164)</u>	<u>\$ (103)</u>		
Average revenues per MWh:					
Residential	\$ 147.43	\$ 117.86	\$ 101.88	25.1	15.7
Small business	\$ 146.39	\$ 118.90	\$ 104.87	23.1	13.4
Large business and other customers.....	\$ 96.67	\$ 83.96	\$ 69.54	15.1	20.7
Estimated share of ERCOT retail markets (e)(f):					
Historical service territory:					
Residential.....	65%	72%	81%		
Small business.....	64%	71%	78%		
Total ERCOT:					
Residential.....	37%	39%	44%		
Small business.....	26%	29%	31%		
Large business and other customers	14%	20%	33%		

(a) Customers with demand of less than 1 MW annually.

(b) See Note 1 to Financial Statements for discussion of reporting of trading and ERCOT balancing activity in 2006.

(c) Includes a \$162 million charge for a special customer appreciation bonus. This charge does not affect the computation of residential average revenues per MWh. See Note 7 to Financial Statements.

(d) Includes physical commodity trading activity not subject to mark-to-market accounting of \$34 million in net losses, \$61 million in net gains and \$13 million in net gains in 2006, 2005 and 2004, respectively.

(e) Based on number of meters.

(f) Estimated market share is based on the number of customers that have choice.

TXU Energy Holdings Segment

Production, Purchased Power and Delivery Cost Data

	Year Ended December 31,			Change % 2006/2005	Change % 2005/2004
	2006	2005	2004		
Fuel, purchased power costs and delivery fees (\$ millions):					
Nuclear fuel	\$ 85	\$ 78	\$ 82	9.0	(4.9)
Lignite/coal	<u>475</u>	<u>475</u>	<u>506</u>	—	<u>(6.1)</u>
Total baseload fuel	560	553	588	1.3	(6.0)
Natural gas fuel and purchased power	1,787	3,285	2,820	(45.6)	16.5
Other costs	<u>228</u>	<u>281</u>	<u>221</u>	<u>(18.9)</u>	<u>27.1</u>
Fuel and purchased power costs (a)	2,575	4,119	3,629	(37.5)	13.5
Delivery fees (b)	<u>1,353</u>	<u>1,426</u>	<u>1,544</u>	<u>(5.1)</u>	<u>(7.6)</u>
Total	<u>\$3,928</u>	<u>\$5,545</u>	<u>\$5,173</u>	<u>(29.2)</u>	<u>7.2</u>
Fuel and purchased power costs (which excludes generation plant operating costs) per MWh:					
Nuclear fuel	\$ 4.29	\$ 4.23	\$ 4.31	1.4	(1.9)
Lignite/coal (c)	\$ 12.20	\$ 11.68	\$ 12.96	4.5	(9.9)
Natural gas fuel and purchased power	\$ 62.99	\$ 60.37	\$ 47.88	4.3	26.1
Delivery fee per MWh	\$ 25.71	\$ 24.20	\$ 21.75	6.2	11.3
Production and purchased power volumes (GWh):					
Nuclear	19,795	18,371	18,979	7.8	(3.2)
Lignite/coal	<u>43,837</u>	<u>44,005</u>	<u>42,339</u>	<u>(0.4)</u>	<u>3.9</u>
Total baseload generation	63,632	62,376	61,318	2.0	1.7
Natural gas-fueled generation	3,989	3,504	4,726	13.8	(25.9)
Purchased power (a)	<u>24,380</u>	<u>50,920</u>	<u>54,394</u>	<u>(52.1)</u>	<u>(6.4)</u>
Total energy supply	92,001	116,800	120,438	(21.2)	(3.0)
Less line loss and power imbalances	<u>2,146</u>	<u>1,836</u>	<u>3,451</u>	<u>16.9</u>	<u>(46.8)</u>
Net energy supply volumes	<u>89,855</u>	<u>114,964</u>	<u>116,987</u>	<u>(21.8)</u>	<u>(1.7)</u>
Baseload capacity factors (%):					
Nuclear	98.8%	91.5%	94.3%	8.0	(3.0)
Lignite/coal	89.1%	89.8%	86.0%	(0.8)	4.4
Total baseload	91.8%	90.3%	88.4%	1.7	2.1

(a) See Note 1 to Financial Statements for discussion of reporting of trading and ERCOT balancing activity in 2006.

(b) Includes delivery fee charges from TXU Electric Delivery that are eliminated in consolidation (\$1.144 billion, \$1.285 billion and \$1.417 billion in 2006, 2005 and 2004, respectively).

(c) Includes depreciation and amortization of lignite mining assets, which is reported in the depreciation and amortization expense line item, but is part of overall fuel costs.

TXU Energy Holdings Segment

2006 Compared to 2005

Operating revenues decreased \$3 million to \$9.5 billion in 2006.

	Year Ended December 31,		Increase (Decrease)
	2006	2005	
Retail electricity revenues	\$6,953	\$6,330	\$623
Accrued customer appreciation bonus	(162)	—	(162)
Wholesale electricity revenues	2,278	2,807	(529)
Wholesale balancing activities	(31)	225	(256)
Results of risk management and trading activities	153	(164)	317
Other operating revenues	358	354	4
Total operating revenues	<u>\$9,549</u>	<u>\$9,552</u>	<u>\$(3)</u>

The 10% increase in retail electricity revenues reflected the following:

- Higher average pricing contributed \$1.3 billion to the revenue increase. Higher retail prices reflected increases in natural gas prices that resulted in the regulatory-approved price-to-beat rate increases implemented in May 2005, October 2005 and January 2006.
- The effect of higher retail pricing was partially offset by \$667 million in lower retail volumes. Total retail sales volumes declined 11%. Residential and small business volumes fell 10% on a net loss of customers due to competitive activity and lower average consumption per customer. The lower consumption reflected customer efficiency measures in response to prices and warmer weather. Large business market sales volumes declined 11% as the effect of fewer customers was partially offset by higher average consumption per customer. A change in large business customer mix reflected a continuing strategy to improve margins.
- Retail electricity customer counts at December 31, 2006 declined 6% from December 31, 2005. Total residential and small business customer counts in the historical service territory declined 8% and in all combined territories declined 6%.

A \$162 million (\$105 million after-tax) charge was recorded in the fourth quarter of 2006 for a special residential customer appreciation bonus. See discussion in Note 7 to Financial Statements.

The decline in wholesale electricity revenues reflected the reporting of wholesale electricity trading activity on a net basis in 2006 as described in Note 1 to Financial Statements. This effect was partially offset by higher wholesale sales prices.

Wholesale balancing net revenues/purchases are subject to high variability as the activity represents intraday purchases and sales transactions with ERCOT for real-time balancing purposes as measured in 15-minute intervals. See Note 1 for a discussion regarding the change in reporting of ERCOT balancing activities.

Results from risk management and trading activities include realized and unrealized gains and losses associated with financial instruments used for economic hedging and trading purposes, as well as gains and losses on physical sales and purchases of commodities for trading purposes (principally natural gas). Because most of the hedging and risk management activities are intended to mitigate the risk of commodity price movements on revenues and fuel and purchased power costs, the changes in such results should not be viewed in isolation, but rather taken together with the effects of pricing and cost changes on gross margin. Following is an analysis of activities in 2006:

Results associated with the long-term hedging program

- \$205 million in unrealized cash flow hedge ineffectiveness net gains, which includes \$209 million in net gains on unsettled positions and \$4 million in net losses that represent reversals of previously recorded unrealized net gains on positions settled in the current period;
- \$135 million in unrealized mark-to-market net gains on unsettled economic hedge positions that are not being accounted for as cash flow hedges;
- \$109 million in an unrealized “day one” loss on a related series of commodity price hedges entered into in June 2006 at below-market prices; and
- \$112 million in realized net gains on positions accounted for as cash flow hedges, including the reclassification of \$34 million in net gains accumulated in other comprehensive income at December 31, 2005, to offset hedged electricity revenues recognized in the current period.

Results associated with other risk management and trading activities

- \$52 million in realized net losses on positions accounted for as cash flow hedges and primarily entered into in prior years (largely 2003), including the reclassification of \$36 million in net losses accumulated in other comprehensive income at December 31, 2005, to offset hedged electricity revenues recognized in the current period;
- \$34 million in unrealized cash flow hedge ineffectiveness net gains, which includes \$9 million in net gains on unsettled positions and \$25 million in net gains that represent reversals of previously recorded unrealized net losses on positions settled in the current period;
- \$125 million in realized net losses on settlement of economic hedge positions that offset hedged electricity revenues recognized in the current period; and
- \$54 million in realized net losses on settlement of trading positions.

Gross Margin

	Year Ended December 31,			
	2006	% of Revenue	2005	% of Revenue
Operating revenues	\$ 9,549	100%	\$ 9,552	100%
Costs and expenses:				
Fuel, purchased power costs and delivery fees	3,928	41	5,545	58
Generation plant operating costs	604	6	668	7
Depreciation and amortization	<u>328</u>	<u>4</u>	<u>309</u>	<u>3</u>
Gross margin	<u>\$ 4,689</u>	<u>49%</u>	<u>\$ 3,030</u>	<u>32%</u>

Gross margin increased \$1.7 billion, or 55%, to \$4.7 billion in 2006. This growth primarily reflected the relatively low fuel costs of TXU Energy Holdings' nuclear and lignite/coal-fueled baseload plants, as well as the continued improved productivity of the baseload plants, in an environment of increasing wholesale power prices. The increased wholesale power prices were driven by rising natural gas prices. Retail prices, including price-to-beat rates, were increased in response to higher wholesale prices. In addition to higher retail prices, the gross margin increase reflected \$231 million in unrealized net gains from cash flow hedge ineffectiveness and mark-to-market valuations of positions in the long-term hedging program. An 8% increase in production volumes at the nuclear generation plant also contributed to higher gross margin as this generation represents the lowest marginal cost of electricity to supply retail and wholesale customers. The gross margin performance was tempered by the effects of lower retail sales volumes and the effect of the customer appreciation bonus accrual.

Gross margin as a percent of revenues increased 17 percentage points to 49%. The improvement reflected the following estimated effects:

- higher pricing, as the average retail sales price per MWh rose 23% and the average wholesale sales price per MWh rose 17% (10 percentage point margin increase);
- the effect of reporting wholesale electricity trading activity on a net basis (6 percentage point margin increase);
- the effect of unrealized cash flow hedge ineffectiveness and mark-to-market net gains related to the long-term hedge program (1 percentage point margin increase);
- the combined effect of increased nuclear generation production volumes and less need for purchased electricity volumes (2 percentage point margin increase),

partially offset by:

- lower retail sales volumes (2 percentage point margin decrease); and
- customer appreciation bonus (1 percentage point margin decrease).

Fuel, purchased power costs and delivery fees declined \$1.6 billion, or 29%, to \$3.9 billion reflecting the reporting of wholesale trading activity on a net basis in 2006 as discussed in Note 1 to the Financial Statements and the favorable impact of higher nuclear generation volumes to meet sales demand, partially offset by the effect of higher average prices of purchased electricity.

Operating costs decreased \$64 million, or 10%, to \$604 million in 2006. The decrease reflected:

- \$49 million in lower maintenance costs due to both nuclear generation units having scheduled refueling outages in 2005 compared to one in 2006, and reduced other maintenance activity;
- \$9 million in lower incentive compensation expense; and
- the absence of \$10 million in combustion turbine lease expense in 2006 resulting from the purchase of a lease trust interest in early 2006 (see Note 4 to Financial Statements),

partially offset by \$8 million in net severance and early retirement costs associated with generation outsourcing services agreements entered into in early 2006.

Depreciation and amortization (consisting almost entirely of amounts related to generation plants shown in the gross margin table above) increased \$21 million, or 7%, to \$334 million reflecting higher costs associated with mining land reclamation activities and increased amortization of intangible software assets, partially offset by \$7 million in lower depreciation due to the impairment of natural gas-fueled generation plants in the second quarter of 2006.

SG&A expenses increased by \$49 million, or 9%, to \$571 million in 2006. The increase reflected:

- \$39 million in costs associated with the new generation development programs, principally salaries and consulting expenses;
- \$14 million in higher bad debt expense reflecting higher retail accounts receivable balances due to higher prices and the effect of a temporary regulatory-mandated deferred payment arrangement and disconnect moratorium applicable to certain retail customers;
- \$14 million in higher fees related to the sale of accounts receivable program due to higher interest rates; and
- \$6 million in executive severance expense (including amounts allocated from TXU Corp.),

partially offset by:

- \$8 million in lower consulting fees primarily reflecting expenses in 2005 for the development and implementation of the TXU Operating System to improve productivity;
- \$7 million in lower stock-based incentive compensation and deferred compensation expenses; and
- \$7 million in lower salaries resulting from cost reduction initiatives in late 2005.

Franchise and revenue-based taxes increased \$12 million, or 11%, to \$126 million reflecting higher state gross receipts taxes due to higher revenues.

Other income totaled \$17 million in 2006 and \$64 million in 2005. The 2006 amount includes \$11 million in gains on the sale of undeveloped land and a \$2 million insurance recovery related to a generation plant outage in 2001.

The 2005 amount included:

- \$33 million in gains on the sale of undeveloped land and mining land;
- an \$8 million insurance recovery related to a generation plant fire in 2002;
- a \$7 million gain on the sale of an investment in an out-of-state electricity transmission project;
- a \$4 million gain in connection with a customer's termination of an electricity services contract; and
- a \$2 million gain on the sale of surplus equipment.

Other deductions totaled \$215 million in 2006 and \$15 million in 2005. The 2006 amount includes:

- a \$198 million charge related to the write-down of the natural gas-fueled generation plants to fair value (see Note 6 to Financial Statements);
- \$10 million in equity losses (representing amortization expense) related to the ownership interest in the TXU Corp. subsidiary holding the capitalized software licensed to Capgemini;
- \$6 million of litigation-related charges; and
- a \$5 million charge for the termination of an equipment purchase agreement,

partially offset by a \$12 million credit related to the favorable settlement of a counterparty default under a coal contract (as noted below, the original charge related to the default was recorded in this line item).

The 2005 amount includes:

- a \$12 million charge related to a counterparty default under a coal contract;
- \$12 million in transition costs associated with the Capgemini outsourcing agreement;
- \$7 million in equity losses (representing amortization expense) related to the ownership interest in the TXU Corp. subsidiary holding the capitalized software licensed to Capgemini;
- \$6 million in accretion expense related to a lease liability for combustion turbines no longer operated for TXU Energy Holdings' benefit;
- a \$16 million net credit from a reduction in the combustion turbine lease liability due to a change in estimated sublease proceeds. As the original charge associated with this liability was reported in this line item, the related credit was similarly reported; and
- the release of a previously recorded \$6 million reserve for restoration of a site that is now expected to be used in generation plant development.

Interest income increased by \$132 million to \$202 million in 2006 reflecting \$91 million due to higher average advances to affiliates and \$41 million due to higher average rates.

Interest expense and related charges decreased by \$5 million, or 1%, to \$388 million in 2006. The decrease reflects \$29 million of higher capitalized interest, partially offset by higher average interest rates of \$24 million.

Income tax expense on income from continuing operations totaled \$1.2 billion in 2006 compared to \$687 million in 2005. The effective tax rate was 34.4% in 2006 compared to 32.5% in 2005. The 2006 amount included a charge of \$44 million (a 1.2 percentage point effective tax rate impact) representing an adjustment to deferred tax liabilities arising from the enactment of the Texas margin tax as described in Note 10 to the Financial Statements. The 2005 amount reflected a benefit of \$29 million representing a tax reserve adjustment (1.4 percentage point effective tax rate impact) and a charge of \$10 million (a 0.5 percentage point effective tax rate impact) related to the settlement of the IRS audit for the 1994 to 1996 years.

Income from continuing operations increased \$934 million, or 65%, to \$2.4 billion in 2006 driven by improved gross margin and higher interest income, partially offset by the charge for the write-down of the natural gas-fueled generation plants and expenses related to the new generation development program.

TXU Energy Holdings Segment

2005 Compared to 2004

Operating revenues increased \$1.2 billion, or 14%, to \$9.6 billion in 2005. Retail electricity revenues decreased \$40 million, or 1%, to \$6.3 billion.

- The retail revenue decline reflected a \$1.1 billion decrease attributable to a 17% drop in sales volumes, primarily reflecting a net loss of customers due to competitive activity, particularly in the large business market, partially offset by the effect of warmer weather. A total volume decline of 38% in the large business market also reflected a strategy to improve margins. Total residential and small business volumes fell 6%, driven by competitive activity and stricter disconnect policies and more focused collection activities, partially offset by the effect of increased consumption by residential customers due to warmer weather.
- The effect of lower retail volumes was partially offset by \$886 million in higher pricing due to increased price-to-beat rates, reflecting regulatory-approved fuel factor increases in 2005, and higher pricing in the competitive business market, both resulting from the effects of higher natural gas prices. A favorable \$171 million mix shift in the composition of retail sales from large business to residential and small business also offset the effect of lower volumes.
- Retail electricity customer counts at December 31, 2005 declined 8% from December 31, 2004. Total residential and small business customer counts in the historical service territory declined 9% and in all combined territories declined 8%.

Wholesale electricity revenues grew \$921 million, or 49%, to \$2.8 billion reflecting \$777 million in higher prices due to the effect of increased natural gas prices on wholesale electricity prices and \$144 million due to an 8% increase in sales volumes. The wholesale sales volume increase was driven by a shift in the composition of the customer base from retail to wholesale and weather-related increases in wholesale demand.

ERCOT balancing activities resulted in net sales of \$225 million in 2005 and net purchases of \$92 million in 2004. See Note 1 for a discussion regarding the change in reporting of ERCOT balancing activities.

The increase in other revenues of \$12 million primarily reflected higher retail (business customers) natural gas revenues due to increased prices, partially offset by the effect of no longer providing customer care support to TXU Gas after the first half of 2004 and the sale of TXU Fuel in June 2004.

Net losses from hedging and risk management activities, which are reported in revenues and include both realized and unrealized (mark-to-market) gains and losses, totaled \$164 million in 2005 and \$103 million in 2004. Because most of the hedging and risk management activities are intended to mitigate the risk of commodity price movements on revenues and fuel and purchased power costs, the changes in such results should not be viewed in isolation, but rather taken together with the effects of pricing and cost changes on gross margin. Results in 2005 included:

- \$133 million in net realized losses associated with hedges entered into in prior years (largely 2003), the offsetting effects of which are reported in revenues and fuel and purchased power costs. This amount includes \$88 million in losses related to cash flow hedges, which had been recognized in other comprehensive income;
- \$84 million reversal of net unrealized gains previously recognized on power positions settled in the current period, the offsetting effects of which are reported in revenues and fuel and purchased power costs;
- \$79 million in net realized gains on settlement of commodity trading positions largely entered into in 2005 and relating primarily to natural gas; and
- \$31 million of unrealized ineffectiveness losses relating to cash flow hedges principally related to the long-term hedging program.

Gross Margin

	Year Ended December 31,			
	2005	% of Revenue	2004	% of Revenue
Operating revenues	\$ 9,552	100%	\$ 8,402	100%
Costs and expenses:				
Fuel, purchased power costs and delivery fees	5,545	58%	5,173	62%
Generation plant operating costs	668	7%	703	8%
Depreciation and amortization	309	3%	327	4%
Gross margin	<u>\$ 3,030</u>	<u>32%</u>	<u>\$ 2,199</u>	<u>26%</u>

Gross margin increased \$831 million, or 38%, to \$3.0 billion in 2005. This growth primarily reflected the relatively low fuel costs of TXU Energy Holdings' nuclear and lignite/coal-fueled baseload plants, as well as the continued improved productivity of the baseload plants, in an environment of increasing wholesale power prices. The increased wholesale power prices were driven by rising natural gas prices. Retail prices, including price-to-beat rates, were increased in response to higher wholesale prices. The gross margin performance was mitigated by the effect of lower retail sales volumes.

Gross margin as a percent of revenues increased 6 percentage points to 32%. The improvement reflected:

- higher pricing, as the average retail sales price per MWh rose 20%, and the average wholesale sales price per MWh rose 38% (15 percentage point margin increase),

partially offset by:

- higher purchased power costs driven by a 26% increase in average purchased power prices (5 percentage point margin decrease); and
- a 17% decrease in retail sales volumes (4 percentage point margin decrease).

Operating costs decreased \$35 million, or 5%, to \$668 million in 2005. The decline reflected:

- \$30 million in lower benefits expense including \$13 million in lower pension and other postretirement benefit costs (see discussion in SG&A expenses below regarding these costs);
- the absence of \$18 million of costs associated with 9 combustion turbine units no longer operated for TXU Energy Holdings' benefit;
- a \$17 million effect of no longer providing customer care support to TXU Gas (largely offset by lower related revenues), the operations of which were sold in October 2004; and
- the absence of \$8 million of costs associated with the TXU Fuel business sold in June 2004,

partially offset by:

- \$25 million in higher maintenance costs associated with planned nuclear unit outages in 2005, reflecting two outages in 2005 and one outage in 2004; and
- \$15 million in supplier credits recorded in 2004.

Depreciation and amortization (consisting almost entirely of amounts related to generation plants shown in the gross margin table above) decreased \$37 million, or 11%, to \$313 million. The decline included \$19 million due to the effect of the transfer of information technology assets, principally capitalized software, to a TXU Corp. affiliate in connection with the Capgemini outsourcing transaction. The decrease also reflected a \$13 million effect of reduced 2005 depreciation rates for lignite/coal-fueled plants due to extending the estimated useful lives.

SG&A expenses decreased by \$144 million, or 22%, to \$522 million in 2005. The decline reflected:

- a net \$64 million decline due to cost reduction initiatives, including the effect of the Capgemini outsourcing agreement;
- \$41 million in reduced incentive compensation expense including a \$15 million one-time incentive compensation program in wholesale operations in 2004;
- \$38 million in lower bad debt expense as a result of refining and consistently applying credit and collection policies; and
- an \$11 million net decrease in employee retirement-related expenses primarily due to the assumption by TXU Electric Delivery of pension and other postretirement benefit costs related to service of TXU Energy Holdings' employees prior to the unbundling of TXU Corp.'s electric utility business and the deregulation of the Texas electricity industry effective January 1, 2002 (see Note 21 to Financial Statements),

partially offset by \$14 million in higher consulting expense primarily related to development and implementation of the TXU Operating System to improve efficiency of generation plant and mining operations.

Other income totaled \$64 million in 2005 and \$110 million in 2004. Other income in 2005 included:

- \$33 million in gains on the sale of undeveloped land and mining land;
- an \$8 million insurance reimbursement related to a generation plant fire in 2002;
- a \$7 million gain on the sale of an investment in an out-of-state electricity transmission project;
- \$4 million in connection with the termination of a power services contract; and
- \$2 million gain on the sale of surplus equipment.

Other income in 2004 included:

- \$88 million in amortization of the gain on the 2002 sale of two generation plants including \$58 million of the remaining unamortized gain recognized as a result of the termination of a related power purchase and tolling agreement; and
- a \$19 million gain on sale of undeveloped land.

Other deductions totaled \$15 million in 2005 and \$611 million in 2004. The 2005 amount includes:

- a \$12 million charge related to nonperformance of a counterparty in connection with a trading coal contract;
- \$12 million in transition costs associated with the Capgemini outsourcing agreement;
- \$7 million in equity losses (representing depreciation expense) in the TXU Corp. entity holding the capitalized software licensed to Capgemini;
- \$6 million in accretion expense related to the 2004 impairment of a lease for gas-fueled combustion turbines no longer operated for TXU Energy Holdings' benefit;
- a \$16 million net credit adjusting the impairment loss on the leased gas-fueled combustion turbines to reflect actual sub-lease proceeds under the terms of a third-party contract entered into in 2005; and
- the release of a previously recorded \$6 million reserve for restoration of property that is now expected to be used in generation plant development.

The 2004 amount includes:

- \$180 million in lease-related charges primarily related to generation and mining assets taken out of service;
- \$107 million in software write-offs;
- \$107 million for employee severance;
- \$101 million in termination costs for an existing power purchase and tolling agreement; and
- \$79 million for spare parts inventory writedowns.

Interest income increased by \$39 million to \$70 million in 2005 reflecting higher interest on short-term investments and higher average advances to affiliates.

Interest expense and related charges increased by \$40 million, or 11%, to \$393 million in 2005. The increase reflected \$26 million due to higher average interest rates and \$14 million due to higher average debt levels.

The effective income tax rate was 32.5% in 2005 and 28.4% in 2004. The increase reflects the effect of ongoing relatively fixed tax benefits of lignite depletion allowances and amortization of investment tax credits on a significantly higher 2005 income base. The 2005 effective income tax rate also reflects a \$29 million credit for the reversal of previously established tax reserves due to current period events, partially offset by \$10 million in additional tax expense related to settlement of the IRS audit for the 1994 to 1996 tax years.

Income from continuing operations increased \$1.0 billion to \$1.4 billion in 2005 driven by improved gross margin, the effect of restructuring-related charges in 2004 and lower SG&A expenses.

TXU Electric Delivery Segment

Financial Results

	Year Ended December 31,		
	2006	2005	2004
Operating revenues	\$ 2,449	\$ 2,394	\$ 2,226
Costs and expenses:			
Operating costs.....	770	758	730
Depreciation and amortization.....	476	446	389
Selling, general and administrative expenses.....	177	201	219
Franchise and revenue-based taxes	262	247	248
Other income.....	(2)	(4)	(7)
Other deductions	24	11	52
Interest income.....	(58)	(59)	(56)
Interest expense and related charges	<u>286</u>	<u>269</u>	<u>280</u>
Total costs and expenses.....	<u>1,935</u>	<u>1,869</u>	<u>1,855</u>
Income before income taxes, extraordinary gain and cumulative effect of change in accounting principle.....	514	525	371
Income tax expense.....	<u>170</u>	<u>174</u>	<u>116</u>
Income before extraordinary gain and cumulative effect of change in accounting principle	<u>\$ 344</u>	<u>\$ 351</u>	<u>\$ 255</u>

TXU Electric Delivery Segment

Operating Data

	Year Ended December 31,			% Change 2006/2005	% Change 2005/2004
	2006	2005	2004		
Operating statistics – volumes:					
Electric energy delivered (GWh).....	107,098	106,780	101,928	0.3	4.8
Reliability statistics (a):					
System Average Interruption Duration Index (SAIDI) (nonstorm).....	79.09	76.79	75.51	3.0	1.7
System Average Interruption Frequency Index (SAIFI) (nonstorm).....	1.17	1.17	1.10	—	6.4
Customer Average Interruption Duration Index (CAIDI) (nonstorm).....	67.54	65.60	68.75	3.0	(4.6)
Electricity points of delivery (end of period and in thousands):					
Electricity distribution points of delivery (based on number of meters) (b)	3,056	3,013	2,971	1.4	1.4
Operating Revenues:					
Electricity distribution revenues (c):					
Affiliated (TXU Energy Company)	\$ 1,137	\$ 1,276	\$ 1,418	(10.9)	(10.0)
Nonaffiliated	<u>1,046</u>	<u>879</u>	<u>590</u>	<u>19.0</u>	<u>49.0</u>
Total distribution revenues	2,183	2,155	2,008	1.3	7.3
Third-party transmission revenues	236	213	192	10.8	10.9
Other miscellaneous revenues	<u>30</u>	<u>26</u>	<u>26</u>	<u>15.4</u>	<u>—</u>
Total operating revenues	<u>\$ 2,449</u>	<u>\$ 2,394</u>	<u>\$ 2,226</u>	<u>2.3</u>	<u>7.5</u>

- (a) SAIDI is the average number of electric service outage minutes per customer in a year. SAIFI is the average number of electric service interruptions per customer in a year. CAIDI is the average duration in minutes of interruptions to electric service in a year. The statistics presented are based on the preceding twelve months' data.
- (b) Includes lighting sites, primarily guard lights, for which TXU Energy Company is the REP but are not included in TXU Energy Company's customer count. Such sites totaled 82,337, 86,495 and 95,252 at December 31, 2006, 2005 and 2004, respectively.
- (c) Includes transition charges associated with the issuance of securitization bonds totaling \$151 million, \$152 million and \$106 million for the years ended December 31, 2006, 2005 and 2004, respectively. Also includes disconnect/reconnect fees and other discretionary revenues for services requested by REPs.

TXU Electric Delivery Segment

TXU Electric Delivery's future results are expected to be impacted by the effects of the cities rate settlement described in Note 9 to the Financial Statements. Incremental expenses of approximately \$70 million are being recognized almost entirely over the period from May 2006 through June 2008, of which \$18 million has been recognized in the 2006 period.

TXU Electric Delivery's future results are also expected to be impacted by additional transition costs associated with the InfrastruX Energy Services joint venture totaling an estimated \$12 million expected to be expensed in the first half of 2007.

2006 compared to 2005

Operating revenues increased \$55 million, or 2%, to \$2.4 billion in 2006. Delivered volumes rose less than 1%. The revenue increase reflected:

- \$24 million in higher transmission revenues primarily due to rate increases approved in 2005 and 2006 to recover ongoing investment in the transmission system;
- an estimated \$16 million due to growth in points of delivery; and
- \$9 million from increased distribution tariffs to recover higher transmission costs.

The effect of warmer weather on electricity consumption was largely offset by end-user efficiency measures in response to higher prices and warmer weather.

Gross Margin

	Year Ended December 31,			
	2006	% of Revenue	2005	% of Revenue
Operating revenues	\$ 2,449	100%	\$ 2,394	100%
Costs and expenses:				
Transmission and distribution system operating costs.....	770	31%	758	32%
Depreciation and amortization	<u>474</u>	<u>20%</u>	<u>446</u>	<u>18%</u>
Gross margin	<u>\$ 1,205</u>	<u>49%</u>	<u>\$ 1,190</u>	<u>50%</u>

Operating costs rose \$12 million, or 2%, to \$770 million in 2006. The increase reflected \$19 million in increased fees paid to third party transmission entities, partially offset by \$6 million due to increased labor capitalization rates and timing of expenses related to advanced meter installations.

Depreciation and amortization (essentially all of which related to the delivery system as shown in the gross margin table above) increased \$30 million, or 7%, to \$476 million in 2006. The increase reflected \$23 million in depreciation related to normal additions and replacements of property, plant and equipment and a \$4 million adjustment related to capitalized software costs.

SG&A expenses decreased \$24 million, or 12%, to \$177 million in 2006. The decrease reflected:

- \$8 million in lower incentive compensation expense;
- \$4 million in decreased employee benefits expense;
- \$3 million in lower bad debt expense;
- \$3 million in lower legal and consulting fees; and
- \$3 million in lower research and development costs.

partially offset by, \$3 million in higher sale of receivables program fees driven by higher interest rates.

Franchise and revenue-based taxes increased \$15 million, or 6%, to \$262 million in 2006. The increase was driven by higher delivered volumes in the period to which the tax applies and also includes \$5 million in higher franchise fees under the cities rate settlement. See Note 9 to Financial Statements.

Other deductions totaled \$24 million in 2006 and \$11 million in 2005. The 2006 amount includes:

- \$13 million in costs as a result of the cities rate settlement (See Note 9 to Financial Statements);
- \$7 million in transition costs related to the InfrastruX Energy Services joint venture; and
- \$4 million in equity losses (representing amortization expense) related to the ownership interest in the TXU Corp. subsidiary holding the capitalized software licensed to Capgemini.

The 2005 amount included:

- \$3 million in costs associated with transitioning the outsourced activities to Capgemini;
- \$3 million in equity losses (representing amortization expense) related to the ownership interest in the TXU Corp. subsidiary holding the capitalized software licensed to Capgemini; and
- \$2 million of severance-related charges related to the 2004 restructuring actions.

Interest expense increased \$17 million, or 6%, to \$286 million in 2006 due to higher average balances of commercial paper outstanding.

Income tax expense totaled \$170 million in 2006 compared to \$174 million in 2005. The effective tax rate was comparable at 33.1% for both 2006 and 2005.

Net income decreased \$7 million, or 2%, to \$344 million driven by costs associated with the cities rate settlement and expenses related to the InfrastruX Energy Services agreement.

TXU Electric Delivery Segment

2005 compared to 2004

Operating revenues increased \$168 million, or 8%, to \$2.4 billion in 2005. This change reflected:

- \$46 million in higher transition charges associated with the issuance of securitization bonds in June 2004 (offset in total by higher amortization of the related regulatory asset as discussed below);
- approximately \$30 million related to warmer summer weather;
- \$22 million from continued implementation of power factor billing (power factor billing is a tariff adjustment applied to nonresidential end-use consumers that utilize inefficient equipment);
- \$21 million in base growth reflecting an increase in points of delivery;
- \$21 million from increased distribution tariffs to recover higher transmission costs; and
- \$21 million in increased transmission revenues due to rate increases approved in 2005 and 2004 and higher volumes.

Gross Margin

	Year Ended December 31,			
	2005	% of Revenue	2004	% of Revenue
Operating revenues	\$ 2,394	100%	\$ 2,226	100%
Costs and expenses:				
Transmission and distribution system operating costs.....	758	32%	730	33%
Depreciation and amortization	<u>446</u>	<u>18%</u>	<u>386</u>	<u>17%</u>
Gross margin	<u>\$ 1,190</u>	<u>50%</u>	<u>\$ 1,110</u>	<u>50%</u>

Gross margin increased \$80 million, or 7%, to \$1.2 billion in 2005. The increase was driven by higher operating revenues.

Operating costs rose \$28 million, or 4%, to \$758 million. This increase reflected:

- \$13 million in increased spending for system reliability initiatives;
- \$7 million in higher property taxes primarily due to increased investments in property;
- \$4 million in increased metering expenses due to increased labor costs to accommodate increased consumer requested activities;
- \$3 million in increased third-party transmission costs due to increased rates; and
- \$3 million in higher transportation expense due to an increase in fuel and lease costs,

partially offset by:

- \$4 million in decreased employee benefits costs, reflecting lower health care costs due to plan changes; and
- \$4 million in reduced pension and OPEB costs. This reduction reflects an amendment to PURA as discussed in Note 21 to Financial Statements.

Depreciation and amortization (consisting almost entirely of amounts shown in the gross margin table above) increased \$57 million, or 15%, to \$446 million in 2005. The increase reflected \$46 million in higher amortization of regulatory assets associated with the issuance of transition bonds (offsetting the same amount of revenue increase) and \$14 million in higher depreciation due to normal additions and replacements of property, plant, and equipment, partially offset by a \$3 million decline reflecting the July 2004 transfer of information technology assets, principally capitalized software, to a TXU Corp. affiliate in connection with the Capgemini outsourcing transaction.

SG&A expense decreased \$18 million, or 8%, to \$201 million in 2005. The decline included:

- \$16 million from cost reduction initiatives including the effects of the Capgemini agreement;
- \$5 million in decreased employee benefits, reflecting lower health care costs due to plan changes; and
- \$2 million in reduced pension and OPEB costs, as a result of the amendment to PURA,

partially offset by \$3 million higher bad debt expense largely resulting from the establishment of an allowance for uncollectible accounts based on a credit-scoring methodology applied to outstanding REP accounts receivable.

Other deductions totaled \$11 million in 2005 and \$52 million in 2004. The 2005 amount included:

- \$3 million in costs associated with transitioning the outsourced activities to Capgemini;
- \$3 million in equity losses (representing amortization expense) related to the ownership interest in the TXU Corp. subsidiary holding the capitalized software licensed to Capgemini, and
- \$2 million of severance-related charges resulting from the 2004 restructuring actions.

The 2004 amount included:

- a \$21 million charge for estimated settlement payments arising from the 2004 cities rate settlement;
- \$20 million of severance-related charges in connection with the Capgemini outsourcing transaction and other TXU Corp. restructuring actions; and
- \$8 million related to transitioning the outsourced activities to Capgemini, including asset write-downs and other unusual charges.

Interest expense decreased \$11 million, or 4%, to \$269 million in 2005. The decrease includes \$9 million from the impact of lower average interest rates and \$2 million due to an increase in allowance for funds used during construction (capitalized interest) on higher construction expenditures.

The effective income tax rate increased to 33.1% in 2005 from 31.3% in 2004. The increase is due primarily to the effect of ongoing relatively fixed amortization of tax benefits (statutory tax rate changes and investment tax credits) on a higher 2005 income base, partially offset by \$4 million credit in 2005 arising from the settlement of the IRS audit for the 1994 through 1996 tax years.

Income before extraordinary gain and cumulative effect of a change in accounting principle (an after-tax measure) increased \$96 million, or 38%, to \$351 million. This increase was driven by higher operating revenues and the impact of unusual charges in 2004 reported in other deductions.

COMPREHENSIVE INCOME – Continuing Operations

Cash flow hedge activity reported in other comprehensive income from continuing operations included (all amounts after-tax):

	<u>Year Ended December 31,</u>		
	<u>2006</u>	<u>2005</u>	<u>2004</u>
Net increase (decrease) in fair value of cash flow hedges (all commodity) held at end of period.....	\$ 568	\$ (47)	\$ (75)
Derivative value net losses (gains) reported in net income that relate to hedged transactions recognized in the period:			
Commodities.....	(23)	64	21
Financing – interest rate swaps (a).....	<u>8</u>	<u>13</u>	<u>23</u>
	(15)	77	44
Total income (loss) effect of cash flow hedges reported in other comprehensive from continuing operations	<u>\$ 553</u>	<u>\$ 30</u>	<u>\$ (31)</u>

(a) Represents recognition of net losses on settled swaps.

TXU Corp. has historically used, and expects to continue to use, derivative instruments that are effective in offsetting future cash flow variability in interest rates and energy commodity prices. The amounts included in accumulated other comprehensive income are expected to offset the impact of rate or price changes on forecasted transactions. Amounts in accumulated other comprehensive income include (i) the value of open cash flow hedges (for the effective portion), based on current market conditions, and (ii) the value of dedesignated and terminated cash flow hedges at the time of such dedesignation, less amounts reclassified to earnings as the original hedged transactions are recognized, unless the hedged transactions become probable of not occurring. The effects of the hedge will be recorded in the statement of income as the hedged transactions are actually settled and affect earnings. Also see Note 19 to Financial Statements.

See discussion in Note 21 to Financial Statements regarding the minimum pension liability adjustments reported in other comprehensive income.

FINANCIAL CONDITION

LIQUIDITY AND CAPITAL RESOURCES

Cash Flows — Cash flows provided by operating activities in 2006 increased \$2.2 billion, or 77%, to \$4.9 billion. The improvement reflected:

- higher operating earnings after taking into account noncash items such as deferred federal income taxes, unrealized mark-to-market valuations and the generation plant impairment charge;
- a favorable change of \$503 million in net margin deposits, primarily reflecting amounts received from counterparties related to natural gas positions in the long-term hedging program; and
- a favorable change of \$293 million in working capital (accounts receivable, accounts payable and inventories) driven by higher wholesale natural gas and electricity receivables in 2005 due to higher prices in the fourth quarter of 2005.

Cash flows provided by operating activities in 2005 increased \$1.0 billion, or 59%, to \$2.8 billion. The increase was driven by higher earnings.

Cash flows used in financing activities were \$2.3 billion in 2006, \$1.6 billion in 2005 and \$6.5 billion in 2004. The drivers of the \$769 million increase in cash used in finance activities from 2005 to 2006 and the \$5.0 billion decrease in cash used in financing activities from 2004 to 2005 are summarized in the table below:

	Year Ended December 31,		
	2006	2005	2004
Cash used in financing activities:			
Net issuances and (repayments) of borrowings, including premiums and discounts	\$ (777)	\$ 356	\$ 155
Net repurchases of common stock	(832)	(1,054)	(4,575)
Repurchase of preference stock	—	(300)	—
Repurchase of preferred securities of subsidiaries	—	(38)	(75)
Repurchase of exchangeable preferred membership interests.....	—	—	(1,852)
Payment of common stock dividends	(764)	(544)	(150)
Payment of preference stock dividends	—	(11)	(22)
Excess tax benefit on stock-based compensation	41	28	—
Total.....	<u>\$ (2,332)</u>	<u>\$ (1,563)</u>	<u>\$ (6,519)</u>

Investing activities used cash flows of \$2.7 billion in 2006, \$1.0 billion in 2005 and provided cash flows of \$4.3 billion in 2004. The table below details the business activities impacting investing cash flows.

	<u>Year Ended December 31,</u>		
	<u>2006</u>	<u>2005</u>	<u>2004</u>
Cash provided by (used in) investing activities:			
Capital expenditures, including nuclear fuel	\$ (2,297)	\$ (1,104)	\$ (999)
Sale of TXU Australia.....	—	—	1,885
Disposition of TXU Gas	—	—	1,905
Sale of TXU Fuel	—	—	500
Sale of telecommunications business	—	—	524
Purchase of lease trust.....	(69)	—	—
Deposit of proceeds from pollution control revenue bonds with trustee	(240)	—	—
Proceeds from sale of assets	20	77	27
Return of investment in trust to support a credit facility.....	—	—	525
Investment in unconsolidated affiliate.....	(15)	—	—
Net investments in nuclear decommissioning trust fund securities	(16)	(15)	(15)
Costs to remove retired property.....	(40)	(44)	(40)
Other	(7)	48	(32)
Total.....	<u>\$ (2,664)</u>	<u>\$ (1,038)</u>	<u>\$ 4,280</u>

Depreciation and amortization expense reported in the statement of cash flows exceeds the amount reported in the statement of income by \$63 million, \$60 million and \$66 million for 2006, 2005 and 2004, respectively. This difference represents amortization of nuclear fuel, which is reported as fuel costs in the statement of income consistent with industry practice.

Capital Allocation — TXU Corp. expects to incur the following capital expenditures and distributions in 2007 in accordance with its capital allocation model:

- \$770 million for increased investment in TXU Electric Delivery’s transmission and distribution infrastructure;
- \$2.1 billion for investments in generation activities, including \$1.3 billion for construction of one generation unit at Sandow and two generation units at Oak Grove; and
- pay regular cash dividends at levels authorized by the board of directors, which currently is in the amount of \$1.73 per share annually.

TXU Corp. may be restricted in applying its current capital allocation model by virtue of the terms of the Merger Agreement. In particular, TXU Corp. may be required to obtain consent to make certain capital expenditures or to pay quarterly dividends in excess of 43.25 cents per share.

Long-term Debt Activity — During 2006, TXU Corp. reacquired or made scheduled principal payments on long-term debt as follows (all amounts presented are principal):

	<u>Repayments and Repurchases</u>
TXU Corp.:	
Senior notes	\$ 733
Equity-linked senior notes.....	179
Other long-term debt.....	10
TXU Energy Company:	
Pollution control revenue bonds	259
Senior notes	400
Other long-term debt.....	5
TXU Electric Delivery:	
Transition bonds.....	93
US Holdings.....	<u>12</u>
Total	<u>\$ 1,691</u>

Issuances in 2006 totaled \$243 million in pollution control revenue bonds at TXU Energy Company. Scheduled principal payments in 2007 total \$485 million.

Interest rate swaps related to \$300 million and \$1.8 billion principal amount of debt were dedesignated as fair value hedges in December 2006 and January 2007, respectively. Offsetting swap positions were entered into, and both the original swaps and offsetting positions are subsequently being marked-to-market in net income.

See Note 15 to Financial Statements for further detail of long-term debt and other financing arrangements.

Credit Facilities — At February 28, 2007, subsidiaries of TXU Corp. had access to credit facilities totaling \$6.5 billion of which \$4.4 billion was unused. A \$1.5 billion facility maturing in May 2007 will be terminated on March 1, 2007. TXU Corp. has entered into a commitment agreement for replacement of the facility with a new 364-day facility on terms comparable to the existing facilities and expects to execute a new \$1.5 billion credit facility under this commitment in March 2007. Available facilities at February 28, 2007 declined \$900 million from year-end 2006 primarily due to borrowings to repay maturing commercial paper as rating agency actions reduced TXU Corp.'s ability to reissue these borrowings (see discussion below under "Credit Ratings").

Registered Financing Arrangements —TXU Corp. currently has an effective shelf registration statement on file with the SEC for issuances of up to \$2.0 billion of equity securities, equity-linked debt securities, debt securities and/or preferred securities of subsidiary trusts.

Capitalization — The capitalization ratios of TXU Corp. at December 31, 2006, consisted of 83.2% long-term debt, less amounts due currently, and 16.8% common stock equity. Total debt to capitalization, including short-term debt, was 85.5% and 96.6% at December 31, 2006 and 2005, respectively.

Financing of Investments in New Generation Facilities and Cleaner Coal-fueled Generation Technologies — Funding of these initiatives is expected to be sourced from the issuance of debt and cash flows from operations.

Pension Protection Act — In August 2006, the Pension Protection Act of 2006 (the Act) was signed into law. The Act which will be phased in over the next few years is expected to increase pension plan funding and require additional plan disclosures in regulatory filings and to plan participants. Pension funding for TXU Corp. is expected to total \$126 million in 2007 and \$94 million in 2008, including the effects of the Act. Contributions to the pension plan in 2006 totaled \$4 million.

Income Tax Payments – Excluding the effects of any potential transactions or audit settlements with the IRS, federal income tax payments in 2007 are estimated to total approximately \$505 million. Federal income tax payments totaled \$220 million in 2006.

Short-term Borrowings — At February 28, 2007, subsidiaries of TXU Corp. had \$1.4 billion of commercial paper outstanding and \$1.1 billion of bank borrowings under credit facilities, both of which fund short-term liquidity requirements.

Dividends – On November 3, 2006, the TXU Corp. Board of Directors declared a common stock dividend in the amount of 43.25 cents per share, an increase of 5% over the previous quarter, payable on January 2, 2007 to shareholders of record as of December 1, 2006. The increase sets the common stock dividend at an annual rate of \$1.73 per share. On February 15, 2007, TXU Corp.’s board of directors declared a common stock dividend of 43.25 cents per share that will be payable April 2, 2007 to shareholders of record as of March 2, 2007. The dividend rate and annual dividend growth rate will be subject to regular review by TXU Corp.’s Board of Directors and may be changed at any time based upon a number of factors, particularly those factors discussed above under “Risk Factors”.

Under the terms of the Merger Agreement, TXU Corp. cannot declare or pay common stock dividends, except for regular quarterly dividends paid to holders of TXU Corp. common stock in an amount not to exceed 43.25 cents per share per quarter, with record dates of or no earlier than, March 2, 2007; June 1, 2007; September 1, 2007; December 1, 2007; March 1, 2008 and June 1, 2008, respectively. In addition, the Merger Agreement provides that no quarterly dividend will be declared with respect to the quarter in which the proposed merger is consummated unless the merger is consummated after the record date for that quarter.

Common Stock Repurchases — In November 2005, the TXU Corp. Board of Directors authorized the repurchase of up to 34 million shares of common stock through the end of 2006. In November 2006, the TXU Corp. Board of Directors extended this authority to the end of 2007. In addition, in November 2006, the TXU Corp. Board of Directors authorized the repurchase of up to an additional 20 million shares of common stock through the end of 2007. As of February 16, 2007, 31 million shares of the 54 million shares authorized have been repurchased. Under the terms of the Merger Agreement, TXU Corp. and its subsidiaries generally cannot, without the prior written consent of Merger Sub Parent, purchase or otherwise acquire any of TXU Corp.’s shares of common stock.

Sales of Accounts Receivable — Subsidiaries of TXU Corp. participate in an accounts receivable securitization program, the activity under which is accounted for as a sale of accounts receivable in accordance with SFAS 140. Under the program, subsidiaries of TXU Corp. (originators) sell trade accounts receivable to TXU Receivables Company, a consolidated wholly-owned bankruptcy-remote direct subsidiary of TXU Corp., which sells undivided interests in the purchased accounts receivable for cash to special purpose entities established by financial institutions. All new trade receivables under the program generated by the originators are continuously purchased by TXU Receivables Company with the proceeds from collections of receivables previously purchased. Funding under the program totaled \$627 million and \$671 million at December 31, 2006 and 2005, respectively. See Note 13 to Financial Statements for a more complete description of the program including the impact on the financial statements for the periods presented and the contingencies that could result upon the termination of the program.

Liquidity Effects of Risk Management and Trading Activities — As of December 31, 2006, subsidiaries of TXU Corp. have received/posted cash and letters of credit for margin requirements, miscellaneous credit support or as otherwise required by a counterparty as follows:

- \$672 million in cash has been received related to daily margin settled transactions primarily associated with positions in the long-term hedging program;
- \$9 million in cash has been received from counterparties as collateral;
- \$7 million in cash has been posted with counterparties as collateral; and
- \$455 million in letters of credit have been posted with counterparties as collateral.

With respect to collateral received, subsidiaries of TXU Corp. have the contractual right, but not the obligation, to request collateral from certain counterparties based on the value of the contract and the credit worthiness of the counterparty. This collateral is typically held in the form of cash or letters of credit. Collateral received in cash is used for working capital and other corporate purposes, including reducing short-term borrowings under credit facilities. Unless otherwise specified in the contract, counterparties may generally elect to substitute posted cash collateral with letters of credit, reducing TXU Corp.'s liquidity.

Commodity transactions typically require the posting of collateral to support potential future payment obligations if the forward price of the underlying commodity moves such that the hedging instrument is out-of-the-money to the holder. Subsidiaries of TXU Corp. have used cash and letters of credit to satisfy their collateral obligations. Considering the current and expected scale of the long-term hedging program and the desire to reduce the potential effect on liquidity of collateral postings, TXU DevCo's hedging transactions are supported with a first-lien security interest in the assets of TXU Big Brown Company LP (Big Brown Lien) consisting of two existing lignite/coal-fueled generation units.

With respect to positions under the long-term hedging program as of February 28, 2007, for each \$1.00 per MMBtu increase in natural gas prices, TXU Corp.'s liquidity could be reduced by approximately \$1.3 billion in collateral and/or financial margining. Transactions requiring daily margining account for approximately 48% of the positions in the long-term hedging program and are generally met by cash postings. For the remainder, collateral settlements are being met by a combination of the Big Brown Lien, letters of credit and cash postings as required periodically by counterparties.

Financial Covenants, Credit Rating Provisions and Cross Default Provisions — The terms of certain financing arrangements of subsidiaries of TXU Corp. contain financial covenants that require maintenance of specified fixed charge coverage ratios and leverage ratios and/or contain minimum net worth covenants. As of December 31, 2006, TXU Corp.’s subsidiaries were in compliance with all such applicable covenants.

Credit Ratings

Credit ratings for TXU Corp. and certain of its subsidiaries as of February 28, 2007 are presented below:

	TXU Corp. (Senior Unsecured)	US Holdings (Senior Unsecured)	TXU Electric Delivery (Senior Unsecured)	TXU Energy Company (Senior Unsecured)
S&P.....	BB+	BB+	BBB-	BBB-
Moody’s.....	Ba1	Baa3	Baa2	Baa2
Fitch.....	BB+	BB+	BBB	BBB-

All the Fitch ratings reflect a one-notch downgrade in late February 2007 as a result of the Merger Agreement announced on February 26, 2007. Fitch also placed all of these ratings on Rating Watch Negative. Further, due to the announcement of the proposed merger, Moody’s has placed all these ratings on review for possible downgrade and S&P has placed all these ratings on CreditWatch negative. Moody’s, S&P’s and Fitch’s rating of TXU Corp.’s senior unsecured debt and S&P’s and Fitch’s rating of US Holdings’ senior unsecured debt are one notch below investment grade.

Commercial paper issued by TXU Energy Company and TXU Electric Delivery is rated P2 by Moody’s and F3 by Fitch and has not been rated by S&P. The Fitch rating reflects a one-notch downgrade in late February 2007.

A rating reflects only the view of a rating agency, and is not a recommendation to buy, sell or hold securities. Any rating can be revised upward or downward at any time by a rating agency if such rating agency decides that circumstances warrant such a change.

Material Credit Rating Covenants

TXU Energy Company has provided a guarantee of the obligations under TXU Corp.’s lease of its headquarters building. In the event of a downgrade of TXU Energy Company’s credit rating to below investment grade, either a guarantee from an investment grade entity or a letter of credit of \$148 million at December 31, 2006 would need to be provided within 30 days of any such rating decline.

Under the terms of a rail car lease with \$51 million in remaining lease payments (principal amount as of December 31, 2006), if TXU Energy Company’s credit rating were downgraded to below investment grade by any specified rating agency, TXU Energy Company could be required to sell the interest in the lease, assign the lease to a new obligor that is investment grade, post a letter of credit or defease the lease.

TXU Energy Company has entered into certain commodity contracts that in some instances give the other party the right, but not the obligation, to request TXU Energy Company to post collateral in the event that its credit rating falls below investment grade. Based on its commodity contract positions at December 31, 2006, in the event TXU Energy Company were downgraded to one level below investment grade by specified rating agencies, counterparties would have the option as specified in the contracts, based on reduced credit thresholds, to request TXU Energy Company to post up to \$65 million in additional collateral requirements. Should TXU Energy Company be downgraded two levels below investment grade, counterparties would have the option to request additional collateral of up to approximately \$31 million. The amount TXU Energy Company could be required to post under these transactions depends in part on the value of the contracts at the time of any downgrade.

ERCOT also has rules in place to assure adequate credit worthiness for parties that schedule power on the ERCOT System. Under these rules, if TXU Energy Company's credit rating were downgraded to below investment grade by any specified rating agency, TXU Energy Company has the contractual obligation and could be required to post collateral of approximately \$33 million as of December 31, 2006.

The adverse liquidity effect in the event of a downgrade of TXU Energy Company's credit rating to one level below investment grade as discussed above totals \$297 million at December 31, 2006. There could be an additional \$31 million (totaling \$328 million) adverse liquidity effect in the event of a downgrade to two levels below investment grade as discussed above.

Other arrangements of TXU Corp. and its subsidiaries, including credit facilities, the sale of receivables program and certain leases, contain terms pursuant to which the interest rates charged under the agreements may be adjusted depending on credit ratings.

Material Cross Default Provisions

Certain financing arrangements contain provisions that may result in an event of default if there were a failure under other financing arrangements to meet payment terms or to observe other covenants that may result in an acceleration of payments due. Such provisions are referred to as "cross default" provisions.

A default by TXU Energy Company or TXU Electric Delivery or any subsidiary thereof in respect of indebtedness in a principal amount in excess of \$50 million may result in a cross default under joint credit facilities totaling \$4.5 billion. Under these credit facilities, a default by TXU Energy Company or any subsidiary thereof may cause the maturity of outstanding balances (\$642 million at December 31, 2006) under such facility to be accelerated as to TXU Energy Company but not as to TXU Electric Delivery. Also, under these credit facilities, a default by TXU Electric Delivery or any subsidiary thereof may cause the maturity of outstanding balances (none as of December 31, 2006) under such facility to be accelerated as to TXU Electric Delivery but not as to TXU Energy Company.

In addition, a default by TXU Energy Company or any subsidiary thereof in respect of indebtedness in a principal amount in excess of \$50 million may result in a cross-default under its 364-day credit facility totaling \$1.5 billion and may cause the maturity of outstanding balances (none as of December 31, 2006) under such facility to be accelerated.

The accounts receivable securitization program also contains a cross default provision with a threshold of \$50 million applicable to each of the originators under the program. TXU Receivables Company and TXU Business Services Company each have a cross default threshold of \$50 thousand. If either an originator, TXU Business Services Company or TXU Receivables Company defaults on indebtedness of the applicable threshold, the facility could terminate.

TXU Corp. and its subsidiaries enter into energy-related and financial contracts, the master forms of which contain provisions whereby an event of default or acceleration of settlement would occur if TXU Corp. or those subsidiaries were to default under an obligation in respect of borrowings in excess of thresholds, which vary, stated in the contracts. The entities whose default would trigger cross default vary depending on the contract.

TXU DevCo's commodity hedging agreement contains a cross default provision. In the event of a default by TXU DevCo under the agreement, including certain cross-acceleration events relating to the indebtedness of TXU DevCo or its subsidiaries in an amount equal to or greater than \$50 million before initial funding under the credit facilities for its new generation development program and \$100 million thereafter, the hedge counterparty may terminate the transactions, including any novated transactions, covered by the hedging agreement.

Other arrangements, including leases, have cross default provisions, the triggering of which would not result in a significant effect on liquidity.

Long-term Contractual Obligations and Commitments — The following table summarizes TXU Corp.’s contractual cash obligations as of December 31, 2006 (see Notes 15 and 16 to Financial Statements for additional disclosures regarding these long-term debt and noncancelable purchase obligations).

<u>Contractual Cash Obligations</u>	<u>Less Than One Year</u>	<u>One to Three Years</u>	<u>Three to Five Years</u>	<u>More Than Five Years</u>	<u>Total</u>
Long-term debt – principal	\$ 474	\$ 1,705	\$ 278	\$ 8,644	\$11,101
Long-term debt – interest (a)	696	1,262	1,134	5,946	9,038
Operating and capital leases (b).....	69	126	111	332	638
Contracts related to generation development program (c)	1,301	896	—	—	2,197
Obligations under commodity purchase and services agreements (d) ...	<u>2,075</u>	<u>2,432</u>	<u>851</u>	<u>1,237</u>	<u>6,595</u>
Total contractual cash obligations (e).....	<u>\$ 4,615</u>	<u>\$ 6,421</u>	<u>\$ 2,374</u>	<u>\$16,159</u>	<u>\$29,569</u>

- (a) Includes net amounts payable under interest rate swaps. Variable interest payments and net amounts payable under interest rate swaps are calculated based on interest rates in effect at December 31, 2006.
- (b) Includes short-term noncancellable leases.
- (c) Amounts represent scheduled payments under the contracts for the three proposed new generation units. See Note 16 to Financial Statements.
- (d) Includes capacity payments, nuclear fuel and natural gas take-or-pay contracts, coal contracts, business services and nuclear-related outsourcing and other purchase commitments. Amounts presented for variable priced contracts assumed the year-end 2006 price remained in effect for all periods except where contractual price adjustment or index-based prices were specified.
- (e) Table does not include estimated 2007 funding of the pension and other postretirement benefits plans totaling approximately \$153 million.

The following contractual obligations were excluded from the table above:

- contracts between affiliated entities and intercompany debt;
- individual contracts that have an annual cash requirement of less than \$1 million (however, multiple contracts with one counterparty that are more than \$1 million on an aggregated basis have been included);
- contracts that are cancelable without payment of a substantial cancellation penalty;
- Cities rate settlement agreement, which is discussed below; and
- employment contracts with management.

Guarantees — See Note 16 to Financial Statements for details of guarantees.

OFF BALANCE SHEET ARRANGEMENTS

TXU Corp. has established an accounts receivable securitization program. See discussion above under “Sale of Receivables” and in Note 13 to Financial Statements.

TXU Corp. has an ownership interest in the Capgemini outsourcing business. See Note 20 to Financial Statements.

Also see Note 16 to Financial Statements regarding guarantees.

COMMITMENTS AND CONTINGENCIES

See Note 16 to Financial Statements for discussion of commitments and contingencies.

CHANGES IN ACCOUNTING STANDARDS

See Notes 1 and 21 to Financial Statements for a discussion of changes in accounting standards.

REGULATION AND RATES

Wholesale Market Activity Investigation — See Note 16 to Financial Statements for discussion.

Climate Change and Carbon Dioxide — See discussion in Part I of this Form 10-K under “Environmental Regulations and Related Considerations” and under “Key Risks and Challenges” above.

2007 Texas Legislative Session

The Texas Legislature convened in its regular biennial session beginning January 9, 2007. This session is not a “sunset” session for the Commission, so there is no requirement that the Legislature consider any electric industry-related bills. However, public statements by key legislators, including the current Chairman of the House Committee on Regulated Industries, which has jurisdiction over electric industry issues in the House, and the Chairman of the Senate Committee on Business and Commerce, which has jurisdiction over electric industry issues in the Senate, indicate a high likelihood that various measures pertaining to the electric industry will be considered. Potential measures that have been or could be introduced and potentially debated or voted upon include initiatives that could affect the competitive framework of the retail electricity market, encourage energy conservation, restore state funding for the low-income customer discount under the “system benefit fund” mechanism, encourage construction of new infrastructure, or enhance customer education regarding the market. TXU Corp. supports continued development of a fully competitive wholesale and retail power market and will actively monitor and provide input regarding legislation that could be material to the electric industry. TXU Corp. is unable to predict the outcome of the 2007 legislative process or its effect, if any, on its ongoing business and, in some limited circumstances, the closing of the proposed merger.

Commission Review of InfrastruX Energy Services Joint Venture

As discussed above under “TXU Electric Delivery Segment Significant Developments”, TXU Corp. and InfrastruX Group have announced the formation of a joint venture, InfrastruX Energy Services, that expects to provide utility operation, construction, power restoration, maintenance and other services. TXU Corp. also announced an agreement between TXU Electric Delivery and InfrastruX Energy Services under which TXU Electric Delivery will receive services from the joint venture. The Commission has announced its desire to gather further information regarding the joint venture. On January 5, 2007, an Order on Briefing Issues and Requests for Hearing was issued granting the request for hearing previously filed by the Joint Parties (Commission Staff, Office of Public Utility Counsel, Texas State Association of Electrical Workers, Texas Industrial Energy Consumers and the Steering Committee of Cities Served by TXU). At its January 25, 2007 open meeting, the Commission decided to hear this case themselves, rather than refer the case to the State Office of Administrative Hearings. A procedural schedule has been adopted, with the hearing scheduled for early May 2007. TXU Electric Delivery cannot predict the ultimate outcome of this process, including its possible effect on the timing of the closing of the transaction.

2006 Cities Rate Settlement

In January 2006 TXU Electric Delivery agreed with a steering committee representing 108 cities in Texas (Cities) to defer the filing of a system-wide rate case with the Commission to no later than June 30, 2008 (based on a test year ending December 31, 2007), unless the Cities and TXU Electric Delivery mutually agree that such a filing is unnecessary. TXU Electric Delivery has extended the benefits of the agreement to 292 nonlitigant cities. Based on the final agreements, including the participation of the nonlitigant cities, expected payments to the cities are estimated to total approximately \$70 million, including incremental franchise taxes.

This amount is being recognized in earnings over the period from May 2006 through June 2008. Payments under the agreement are expected to be made until new tariffs are effective, which based upon an assumed June 2008 rate case filing, is projected to be mid-2009. Payments under the agreement totaled \$18 million in 2006 and are expected to total \$30 million in 2007, \$16 million in 2008 and \$6 million in 2009. See Note 9 to Financial Statements.

Advanced Meter Rulemaking

In 2005, the Texas Legislature passed legislation that authorized utilities to impose a surcharge to recover costs incurred in deploying advanced metering and meter information networks. Benefits of the advanced metering installation include improved safety, on-demand meter reading, enhanced outage identification and restoration and system monitoring of voltages. At December 31, 2006, TXU Electric Delivery had installed approximately 285,000 advanced meters in its service territory and anticipates the installation of up to 500,000 additional advanced meters in 2007, which would represent approximately 25% of the meters on the distribution system. Pursuant to the 2005 legislation, the Commission has initiated rulemaking that addresses various advanced metering issues, including minimum technical standards and cost recovery. TXU Corp. cannot predict the outcome of this rulemaking. Depending upon the results of this rulemaking, TXU Electric Delivery may decide to alter its deployment schedule. TXU Electric Delivery intends to file a surcharge request to seek recovery of investment costs incurred.

Wholesale Market Design

In August 2003, the Commission adopted a rule that, when implemented, will alter the wholesale market design in ERCOT. The rule requires ERCOT:

- to use a stakeholder process to develop a new wholesale market model;
- to operate a voluntary day-ahead energy market;
- to directly assign all congestion rents to the resources that caused the congestion;
- to use nodal energy prices for resources;
- to provide information for energy trading hubs by aggregating nodes;
- to use zonal prices for loads; and
- to provide congestion revenue rights (but not physical rights).

ERCOT currently has a zonal wholesale market structure consisting of four geographic zones. The proposed location-based congestion-management market is referred to as a “nodal” market because wholesale pricing would differ across the various locational nodes on the transmission grid. The implementation of a nodal market is being done in conjunction with transmission improvements designed to reduce current congestion. In March 2006, the Commission approved a set of Nodal Protocols, which was filed by ERCOT and describes the operation of a wholesale nodal market, and set an implementation date of no later than January 1, 2009. In August 2006, the Commission adopted an interim order approving ERCOT’s application for a surcharge imposed on all Qualified Scheduling Entities in ERCOT (including subsidiaries of TXU Energy Company) for the purpose of financing 38% of ERCOT’s expected nodal implementation costs. The surcharge took effect on October 1, 2006. TXU Corp. expects that the annual impact of the surcharge will be approximately \$3 to \$4 million in additional expense; however, TXU Corp. is unable to predict the ultimate impact of the proposed nodal wholesale market design on its operations or financial results.

Transmission Rates

In order to recover increased affiliate and third-party transmission costs from REPs, TXU Electric Delivery is allowed to request an update twice a year to the retail transmission cost recovery factor (TCRF) component of its retail delivery rate. In January 2007, an application was filed to increase the TCRF, which is anticipated to become effective March 1, 2007. This increase is expected to result in an annual increase of \$14 million in the TCRF component of TXU Electric Delivery’s retail delivery rates charged to REPs.

TXU Electric Delivery filed an application for an interim update of its wholesale transmission rate on February 23, 2007. If approved, annualized revenues are expected to increase by approximately \$38 million. Approximately \$23 million of this increase is recoverable through transmission rates charged to wholesale customers, and the remaining \$15 million is recoverable from REPs through the TCRF component of TXU Electric Delivery’s delivery rates charged to REPs.

Disconnect Rulemaking

In June 2006, the Office of Public Utility Counsel and other groups filed a petition asking the Commission to adopt an emergency rule that would bar disconnection of electric service to residential customers during the 2006 summer months. The Commission adopted such a rule in July 2006, which became effective immediately. The new rule required the following for residential customers:

- For “critical care” customers whose interruption or suspension of electric service would create a dangerous or life-threatening condition, disconnection was prohibited through September 30, 2006;
- With respect to elderly low-income customers who contacted their electric provider, disconnection was also prohibited through September 30, 2006. These customers were entitled to enter into a deferred payment arrangement; and
- All other low-income customers were able to avoid disconnection through September 30, 2006 by paying 25% of their current month’s bill and entering into a deferred payment arrangement.

These actions have contributed to the increase in bad debt expense.

2006 Texas Legislative Special Session

The 79th Texas Legislature completed its 3rd special session in May 2006. The session resulted in a reform to the Texas franchise tax system and the enactment of a property tax relief law.

The Texas franchise tax system is being replaced with a new tax system, referred to as the Texas margin tax. The Texas margin tax is a significant change in Texas tax law because it generally makes all legal entities subject to tax, including general and limited partnerships, while the current franchise tax system applies only to corporations and limited liability companies. TXU Corp.’s subsidiaries conduct significant operations through Texas limited partnerships that will become subject to the new Texas margin tax. The effective date of the Texas margin tax is January 1, 2008 for calendar year-end companies and the computation of tax liability is expected to be based on 2007 revenues as reduced by certain deductions. The new margin tax is expected to increase TXU Corp.’s annual state franchise tax expense by approximately \$30 million beginning in 2007. Also see Note 10 to Financial Statements.

The property tax relief law reduced school taxes assessed to TXU Corp. and its subsidiaries by approximately \$12 million in 2006 and is expected to reduce school taxes by \$40 million annually in 2007 and subsequent years (based on current property values and without regard to any property additions).

TXU Electric Delivery Rates

At its January 10, 2007 open meeting, the Commission indicated that it would not require TXU Electric Delivery to file a rate case at this time due to the cities rate settlement discussed above. The Commission stated that it would hold this matter in abeyance until TXU Electric Delivery files its 2006 earnings monitoring report on May 15, 2007.

Price-to-Beat Rates

As a result of the legislation that restructured the electric utility industry in Texas to provide for retail competition (1999 Restructuring Legislation), effective January 1, 2002, REPs affiliated with electricity delivery utilities were required to charge price-to-beat rates, established by the Public Utility Commission of Texas (the Commission), to residential and small business customers located in their historical service territories. The price-to-beat mechanism was intended to spur competition as the rates were set such that competing REPs could profitably offer lower rates. TXU Energy, as a REP affiliated with an electricity delivery utility, was required to charge the price-to-beat rate, adjusted for fuel factor changes, to these classes of customers until the earlier of January 1, 2005 or the date on which 40% of the electricity consumed by customers in that class was supplied by competing REPs. TXU Energy met the 40% threshold target calculation for its small business customers in December 2003 and began offering rates other than the price-to-beat rate to this customer class. Since January 1, 2005, TXU Energy has offered rates different from the price-to-beat rate to all customer classes, but was required to make the price-to-beat rate available for residential and small business customers in its historical service territory until January 1, 2007.

Under amended Commission rules, effective April 2003 through December 2006, affiliated REPs of electricity delivery utilities were allowed to petition the Commission twice a year for a change in the fuel factor component of their price-to-beat rates if the average forward price of natural gas increased or decreased more than 5% (10% if the petition was filed after November 15 of any year) from the level used to set the existing fuel factor component of its price-to-beat rate. Because of rising natural gas prices, in 2005 TXU Energy petitioned and received approval from the Commission for price-to-beat rate increases implemented as follows (percentage represents increase in the average monthly residential bill):

- 10% and 12% in May and October of 2005, respectively. The latter reflected a voluntary discount that expired December 31, 2005; and
- 12% in January of 2006 representing the expiration of the voluntary discount.

As of January 1, 2007, TXU Energy is no longer required to offer the price-to-beat rate to any of its customer classes.

Nuclear Decommissioning

TXU Corp.'s nuclear plant decommissioning costs are fully recoverable from TXU Electric Delivery's distribution customers. Through December 31, 2001, decommissioning costs were recovered from consumers based upon a 1992 site-specific study through rates placed in effect under TXU Corp.'s January 1993 rate increase request. Effective January 1, 2002, decommissioning costs are recovered through a tariff charged to REPs by TXU Electric Delivery based upon a 2000 redetermination of the 1997 site-specific study, adjusted for trust fund assets, as a component of delivery fees effective under TXU Corp.'s 2001 Unbundled Cost of Service filing. In 2005, an updated study of the cost to decommission TXU Corp.'s nuclear generating facility was completed by management and was filed with the Commission in June 2005. The accompanying testimony concluded that no change to the nuclear decommissioning tariff was warranted at that time. In July 2005, the Commission's Policy Development Division issued an order approving the decommissioning cost study and closing the docket.

Provider of Last Resort Rule

In June 2006, the Commission approved a revised Provider Of Last Resort (POLR) rule which became fully effective in January 2007. The rule modifies the existing POLR price structure and creates a rate no longer tied to the price-to-beat rate. Importantly, the newly adopted POLR price structure is designed to compensate POLR providers for the costs and risks associated with providing POLR service and also contains a POLR price floor designed to prevent the POLR price from interfering with competitive market prices.

Reallocation of Stranded Cost Recovery

PURA requires that statewide stranded costs, including regulatory assets, not exceed \$5 billion and any excess would need to be reallocated among retail customer rate classes. The Commission earlier determined that TXU Electric Delivery's share of the excess could not be reallocated because of the Settlement Plan and related financing order, which resolved all allocation issues. In February 2007, the Commission reversed its decision, subjecting TXU Electric Delivery's allocation to further review by the State Office of Administrative Hearings. Any reallocation would not impact the total revenues collected by TXU Electric Delivery, but rather partially shift the transition charges billed to REPs related to the securitization bonds from industrial and commercial to residential rate classes. TXU Electric Delivery believes that the initial decision was correct and cannot determine the ultimate outcome of this proceeding.

Summary

Although TXU Corp. cannot predict future regulatory or legislative actions or any changes in economic and securities market conditions, no changes are expected in trends or commitments, other than those discussed in this report, which might significantly alter its basic financial position, results of operations or cash flows.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

Market risk is the risk that TXU Corp. may experience a loss in value as a result of changes in market conditions affecting commodity prices and interest rates, which TXU Corp. is exposed to in the ordinary course of business. TXU Corp.'s exposure to market risk is affected by a number of factors, including the size, duration and composition of its energy and financial portfolio, as well as the volatility and liquidity of markets. TXU Corp. enters into instruments such as interest rate swaps to manage interest rate risks related to its indebtedness, as well as exchange traded, over-the-counter contracts and other contractual commitments to manage commodity price risk as part of its wholesale activities.

RISK OVERSIGHT

TXU Corp.'s wholesale operation manages the commodity price, counterparty credit and operational risk related to the unregulated energy business within limitations established by senior management and in accordance with TXU Corp.'s overall risk management policies. Interest rate risks are managed centrally by the corporate treasury function. Market risks are monitored daily by risk management groups that operate and report independently of the wholesale commercial operations, utilizing industry accepted practices and analytical methodologies. These techniques measure the risk of change in value of the portfolio of contracts and the hypothetical effect on this value from changes in market conditions and include, but are not limited to, Value at Risk (VaR) methodologies.

TXU Corp. has a corporate risk management organization that is headed by a Chief Risk Officer. The Chief Risk Officer, through his designees, enforces all applicable risk limits, including the respective policies and procedures to ensure compliance with such limits and evaluates the risks inherent in the various businesses of TXU Corp. and their associated transactions. Key risk control activities include, but are not limited to, credit review and approval, operational and market risk measurement, validation of transaction capture, portfolio valuation and daily portfolio reporting, including mark-to-market valuation, VaR and other risk measurement metrics.

COMMODITY PRICE RISK

TXU Corp.'s businesses are subject to the inherent risks of market fluctuations in the price of electricity, natural gas and other energy-related products they market or purchase. TXU Corp.'s businesses actively manage their portfolio of owned generation assets, fuel supply and retail sales load to mitigate the near-term impacts of these risks on results of operations. These businesses, similar to other participants in the market, cannot fully manage the long-term value impact of structural declines or increases in natural gas and power prices and spark spreads (differences between the market price of electricity and its cost of production).

In managing energy price risk, subsidiaries of TXU Corp. enter into a variety of market transactions including, but not limited to, short- and long-term contracts for physical delivery, exchange traded and over-the-counter financial contracts and bilateral contracts with customers. Activities in the wholesale operations include hedging, the structuring of long-term contractual arrangements and proprietary trading. The wholesale operation continuously monitors the valuation of identified risks and adjusts the portfolio based on current market conditions. Valuation adjustments or reserves are established in recognition that certain risks exist until full delivery and settlement of energy has occurred, counterparties have fulfilled their financial commitments and related contracts have either matured or are settled. TXU Corp. strives to use consistent assumptions regarding forward market price curves in evaluating and recording the effects of commodity price risk.

Long-term Hedging Program — See discussion above under “TXU Energy Holdings Segment Significant Developments” for an update of the program, including potential effects on reported results.

VaR Methodology — A VaR methodology is used to measure the amount of market risk that exists within the portfolio under a variety of market conditions. The resultant VaR produces an estimate of a portfolio's potential for loss given a specified confidence level and considers among other things, market movements utilizing standard statistical techniques given historical and projected market prices and volatilities. Stress testing of market variables is also conducted to simulate and address abnormal market conditions.

A Monte Carlo simulation methodology is used to calculate VaR and is considered by management to be the most effective way to estimate changes in a portfolio's value based on assumed market conditions for liquid markets. The use of this method requires a number of key assumptions, such as use of (i) an assumed confidence level; (ii) an assumed holding period (i.e. the time necessary for management action, such as to liquidate positions); and (iii) historical estimates of volatility and correlation data.

TXU Corp. regularly reviews its risk analysis metrics. In the course of this review, it was determined that the Cash Flow at Risk metric previously disclosed is not a meaningful measure of actionable commodity price risk. It was also determined that providing a Trading VaR would enhance disclosure. Trading VaR includes all natural gas and electricity-related contracts entered into for trading purposes. TXU Corp. may add or eliminate other metrics in the future in its disclosures of risks.

In a review of the holding period for VaR calculations presented below, TXU Corp. determined that a holding period of five to 60 days, instead of the five-day holding period previously assumed, would be more reflective of the time it would take to liquidate the portfolio, considering the increase in longer-dated positions (principally related to the long-term hedging program) and the associated liquidity effects.

Trading VaR — This measurement estimates the potential loss in fair value, due to changes in market conditions, of all contracts entered into for trading purposes based on a 95% confidence level and an assumed holding period of five to 60 days.

	<u>Year Ended December 31, 2006</u>
Month-end average VaR:	\$ 12
Month-end high VaR:	\$ 30
Month-end low VaR:	\$ 5

VaR for Energy-Related Contracts Subject to Mark-to-Market (MtM) Accounting — This measurement estimates the potential loss in fair value, due to changes in market conditions, of all contracts marked-to-market in net income (principally hedges not accounted for as cash flow hedges and trading positions), based on a 95% confidence level and an assumed holding period as presented below.

	<u>Year Ended December 31, 2006</u>		<u>Year Ended December 31, 2005</u>
	<u>Five to 60 day holding period</u>	<u>Five-day holding period</u>	<u>Five-day holding period</u>
Month-end average MtM VaR:	\$ 149	\$ 48	\$ 19
Month-end high MtM VaR:	\$ 391	\$ 117	\$ 27
Month-end low MtM VaR:	\$ 5	\$ 5	\$ 12

Earnings at Risk (EaR) — This measurement estimates the potential reduction of fair value of expected pretax earnings for the years presented, due to changes in market conditions, of all energy-related contracts marked-to-market in net income and contracts not marked-to-market in net income that are expected to be settled within the fiscal year (physical purchases and sales of commodities). For this purpose, cash flow hedges are also included with transactions that are not marked-to-market in net income. A 95% confidence level is assumed in determining EaR.

	Year Ended December 31, 2006		Year Ended December 31, 2005
	Five to 60 day holding period	Five-day holding period	Five-day holding period
Month-end average EaR:	\$ 156	\$ 56	\$ 23
Month-end high EaR:.....	\$ 387	\$ 112	\$ 41
Month-end low EaR:.....	\$ 21	\$ 21	\$ 3

The increases in the five-day holding period risk measures (MtM VaR and EaR) above are driven by the significant increase in number of positions in the long-term hedging program.

INTEREST RATE RISK

The table below provides information concerning TXU Corp.'s financial instruments as of December 31, 2006 and 2005 that are sensitive to changes in interest rates, which include debt obligations and interest rate swaps. TXU Corp. has entered into interest rate swaps under which it has agreed to exchange the difference between fixed-rate and variable-rate interest amounts calculated with reference to specified notional principal amounts at dates that generally coincide with interest payments. The weighted average interest rate presented is based on the rate in effect at the reporting date. Capital leases and the effects of unamortized premiums and discounts and fair value hedges are excluded from the table. See Note 15 to Financial Statements for a discussion of changes in debt obligations.

	Expected Maturity Date					There- After	2006	2006	2005	2005
	2007	2008	2009	2010	2011		Total Carrying Amount	Total Fair Value	Total Carrying Amount	Total Fair Value
Equity-linked debt:										
Fixed rate debt amount.....	—	—	—	—	—	—	\$ —	\$ —	\$ 179	\$ 289
Average interest rate.....	—	—	—	—	—	—	—	—	5.80%	—
All other long-term debt: (including current maturities)										
Fixed rate debt										
amount (a).....	\$ 331	\$ 576	\$ 1,129	\$ 135	\$ 143	\$ 8,172	\$ 10,486	\$ 10,669	\$ 11,493	\$ 11,735
Average interest rate.....	4.90%	5.90%	4.81%	5.46%	5.57%	6.46%	6.18%	—	6.14%	—
Variable rate debt amount.....	\$ 143	—	—	—	—	\$ 472	\$ 615	\$ 639	\$ 872	\$ 867
Average interest rate.....	4.11%	—	—	—	—	4.32%	4.27%	—	4.32%	—
Total Debt.....	<u>\$ 474</u>	<u>\$ 576</u>	<u>\$ 1,129</u>	<u>\$ 135</u>	<u>\$ 143</u>	<u>\$ 8,644</u>	<u>\$ 11,101</u>	<u>\$ 11,308</u>	<u>\$ 12,544</u>	<u>\$ 12,891</u>
Debt swapped to variable:										
Amount.....	\$ 200	\$ 450	\$ 450	—	—	\$ 1,700	\$ 2,800	—	\$ 3,400	—
Average pay rate.....	6.66%	8.12%	6.16%	—	—	6.88%	6.95%	—	6.48%	—
Average receive rate.....	5.00%	6.24%	4.80%	—	—	6.18%	5.89%	—	5.97%	—
Debt swapped to fixed:										
Amount.....	—	—	—	—	—	\$ 300	\$ 300	—	\$ —	—
Average pay rate.....	—	—	—	—	—	5.18%	5.18%	—	—	—
Average receive rate.....	—	—	—	—	—	5.37%	5.37%	—	—	—

(a) Reflects the maturity date and not the remarketing date for certain debt that is subject to mandatory tender for remarketing prior to maturity. See Note 15 to Financial Statements for details concerning long-term debt subject to mandatory tender for remarketing.

Interest rate swaps (fixed to variable) related to \$300 million and \$1.8 billion principal amount of debt were redesignated as fair value hedges in December 2006 and January 2007, respectively. Offsetting swap positions were entered into, and both the original swaps and offsetting positions are subsequently being marked-to-market in net income.

As of February 16, 2007, the potential reduction of annual pretax earnings due to a one-point increase in interest rates totaled approximately \$9 million.

CREDIT RISK

Credit Risk — Credit risk relates to the risk of loss associated with nonperformance by counterparties. TXU Corp. and its subsidiaries maintain credit risk policies with regard to their counterparties to minimize overall credit risk. These policies require an evaluation of a potential counterparty's financial condition, credit rating and other quantitative and qualitative credit criteria and specify authorized risk mitigation tools including, but not limited to, use of standardized master netting contracts and agreements that allow for netting of positive and negative exposures associated with a single counterparty. TXU Corp. has standardized documented processes for monitoring and managing credit exposure of its businesses including methodologies to analyze counterparties' financial strength, measurement of current and potential future credit exposures and standardized contract language that provides rights for netting and set-off. Credit enhancements such as parental guarantees, letters of credit, surety bonds and margin deposits are also utilized. Additionally, individual counterparties and credit portfolios are managed to preset limits and analyzed to assess potential credit exposure. This evaluation results in establishing credit limits or collateral requirements prior to entering into an agreement with a counterparty that creates credit exposure. Additionally, TXU Corp. has established controls to determine and monitor the appropriateness of these limits on an ongoing basis. Any prospective material adverse change in the payment history or financial condition of a counterparty or downgrade of its credit quality will result in the reassessment of the credit limit with that counterparty. This process can result in the subsequent reduction of the credit limit or a request for additional financial assurances.

Credit Exposure — Gross exposure of TXU Corp.'s businesses to credit risk, which totaled approximately \$2.0 billion at December 31, 2006, represents trade accounts receivable, as well as net asset positions arising from hedging and trading activities.

Gross assets subject to credit risk include \$595 million in accounts receivable from the retail sale of electricity to residential and small business customers. The risk of material loss (after consideration of bad debt allowances) from nonperformance by these customers is unlikely based upon historical experience. Allowances for uncollectible accounts receivable are established for the potential loss from nonpayment by these customers based on historical experience and market or operational conditions.

Most of the remaining credit exposure is with large business retail customers and wholesale counterparties. These counterparties include energy companies, financial institutions, electric utilities, independent power producers, oil and gas producers, local distribution companies and energy trading and marketing companies. As of December 31, 2006, the exposure to credit risk from these customers and counterparties totaled \$1.2 billion taking into account standardized master netting contracts and agreements described above and \$56 million in credit collateral (cash, letters of credit and other security interests) held by TXU Corp. subsidiaries.

Of this \$1.2 billion net exposure, 88% is with investment grade customers and counterparties, as determined using publicly available information including major rating agencies' published ratings and TXU Corp.'s internal credit evaluation process. Those customers and counterparties without an S&P rating of at least BBB- or similar rating from another major rating agency are rated using internal credit methodologies and credit scoring models to estimate an S&P equivalent rating. TXU Corp. routinely monitors and manages its credit exposure to these customers and counterparties on this basis.

In addition, TXU Electric Delivery has exposure to credit risk totaling \$174 million at December 31, 2006 arising from potential nonperformance by nonaffiliated REPs. This exposure consists almost entirely of noninvestment grade trade accounts receivable.

TXU Corp. is also exposed to credit risk related to the Capgemini put option with a carrying value of \$177 million. Subject to certain terms and conditions, Cap Gemini North America, Inc. and its parent, Cap Gemini S.A., have guaranteed the performance and payment obligations of Capgemini under the services agreements with TXU Energy Company and TXU Electric Delivery, as well as the payment in connection with a put option. S&P currently maintains a BB+ rating with a positive outlook for Cap Gemini S.A.

The following table presents the distribution of credit exposure as of December 31, 2006, for retail trade accounts receivable from large business customers, wholesale trade accounts receivable as well as net asset positions arising from hedging and trading activities, by investment grade and noninvestment grade, credit quality and maturity.

	<u>Net Exposure by Maturity</u>						
	<u>Exposure before Credit Collateral</u>	<u>Credit Collateral</u>	<u>Net Exposure</u>	<u>2 years or less</u>	<u>Between 2-5 years</u>	<u>Greater than 5 years</u>	<u>Total</u>
Investment grade	\$ 1,094	\$ 41	\$ 1,053	\$ 614	\$ 220	\$ 219	\$ 1,053
Noninvestment grade	164	15	149	111	13	25	149
Totals	<u>\$ 1,258</u>	<u>\$ 56</u>	<u>\$ 1,202</u>	<u>\$ 725</u>	<u>\$ 233</u>	<u>\$ 244</u>	<u>\$ 1,202</u>
Investment grade	87%	73%	88%				
Noninvestment grade	13%	27%	12%				

Approximately 60% of the net \$1.2 billion credit exposure has a maturity date of two years or less. TXU Corp. does not anticipate any material adverse effect on its financial position or results of operations due to nonperformance by any customer or counterparty.

TXU Corp.'s subsidiaries had credit exposure to two counterparties each having an exposure greater than 10% of the net \$1.2 billion credit exposure. These two counterparties represented 15% and 12%, respectively, of the net exposure. TXU Corp. views exposure to these two counterparties to be within an acceptable level of risk tolerance as they are rated investment grade.

TXU Corp.'s subsidiaries are exposed to credit risk related to its long-term hedging program. Of the transactions in the program, over 98% of the volumes are with counterparties with an A credit rating or better, and 100% are at least investment grade.

Additionally, under the long-term hedging program, TXU Corp. has potential credit risk exposure concentration related to a single counterparty. A related series of hedge transactions with this counterparty contain certain credit rating provisions that would require the counterparty to post collateral in the form of cash in the event of significant declines in natural gas prices and a material downgrade in the credit rating of the counterparty. TXU Corp. views the potential concentration of risk with this counterparty to be within an acceptable risk tolerance due to the strong financial profile of the counterparty and its A or above credit rating.

FORWARD-LOOKING STATEMENTS

This report and other presentations made by TXU Corp. contain “forward-looking statements” within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, that are included in this report, or made in presentations, in response to questions or otherwise, that address activities, events or developments that TXU Corp. expects or anticipates to occur in the future, including such matters as projections, capital allocation and cash distribution policy, future capital expenditures, business strategy, competitive strengths, goals, future acquisitions or dispositions, development or operation of power production assets, market and industry developments and the growth of TXU Corp.’s business and operations (often, but not always, through the use of words or phrases such as “will likely result,” “are expected to,” “will continue,” “is anticipated,” “estimated,” “projection,” “target,” “outlook”), are forward-looking statements. Although TXU Corp. believes that in making any such forward-looking statement its expectations are based on reasonable assumptions, any such forward-looking statement involves uncertainties and is qualified in its entirety by reference to the discussion of risk factors discussed under “Risk Factors” and the following important factors, among others, that could cause the actual results of TXU Corp. to differ materially from those projected in such forward-looking statements:

- prevailing governmental policies and regulatory actions, including those of the Texas Legislature, the Governor of Texas, FERC, the Commission, the RRC, the NRC, the EPA and the TCEQ, with respect to:
 - allowed prices;
 - allowed rates of return;
 - industry, market and rate structure;
 - purchased power and recovery of investments;
 - operations of nuclear generating facilities;
 - acquisitions and disposal of assets and facilities;
 - development, construction and operation of facilities;
 - decommissioning costs;
 - present or prospective wholesale and retail competition;
 - changes in tax laws and policies; and
 - changes in and compliance with environmental and safety laws and policies, including climate change initiatives;
- continued implementation of the 1999 Restructuring Legislation;
- legal and administrative proceedings and settlements;
- general industry trends;
- TXU Corp.’s ability to attract and retain profitable customers;
- TXU Corp.’s ability to profitably serve its customers given the announced price protection and price cuts;
- restrictions on competitive retail pricing;
- changes in wholesale electricity prices or energy commodity prices;
- unanticipated changes in market heat rates in the Texas electricity market;
- TXU Corp.’s ability to effectively hedge against changes in commodity prices and market heat rates;
- weather conditions and other natural phenomena, and acts of sabotage, wars or terrorist activities;
- unanticipated population growth or decline, and changes in market demand and demographic patterns;
- changes in business strategy, development plans or vendor relationships;
- access to adequate transmission facilities to meet changing demands;
- unanticipated changes in interest rates, commodity prices, rates of inflation or foreign exchange rates;
- unanticipated changes in operating expenses, liquidity needs and capital expenditures;
- commercial bank market and capital market conditions;
- competition for new energy development and other business opportunities;

- inability of various counterparties to meet their obligations with respect to TXU Corp.'s financial instruments;
- changes in technology used by and services offered by TXU Corp.;
- significant changes in TXU Corp.'s relationship with its employees, including the availability of qualified personnel, and the potential adverse effects if labor disputes or grievances were to occur;
- changes in assumptions used to estimate future executive compensation payments;
- significant changes in critical accounting policies material to TXU Corp.;
- actions by credit rating agencies;
- the ability of TXU Corp. to implement cost reduction initiatives;
- with respect to TXU Corp.'s lignite/coal generation development program, more specifically, TXU Corp.'s ability to fund such investments, delays in the approval of, or failure to obtain, air and other environmental permits and the ability to satisfactorily resolve issues relating to any appeal to the final judgement issued with respect to the Sandow consent decree, changes in competitive market rules, changes in environmental laws or regulations, changes in electric generation and emissions control technologies, changes in projected demand for electricity, the ability of TXU Corp. and its contractors to attract and retain, at projected rates, skilled labor for constructing the new generating units, changes in wholesale electricity prices or energy commodity prices, transmission capacity and constraints, supplier performance risk, changes in the cost and availability of materials necessary for the construction program and the ability of TXU Corp. to manage the significant construction program to a timely conclusion with limited cost overruns;
- with respect to the proposed merger: the occurrence of any event, change or other circumstances that could give rise to the termination of the Merger Agreement or the proposed merger; the outcome of any legal proceedings that may be instituted against TXU Corp. and others related to the Merger Agreement; failure to obtain shareholder approval or any other failure to satisfy other conditions required to complete the proposed merger, including required regulatory approvals; risks that the proposed transaction disrupts current plans and operations and the potential difficulties in employee retention as a result of the proposed merger; the amount of the costs, fees, expenses and charges related to the proposed merger and the execution of certain financings that will be obtained to consummate the proposed merger; and the impact of the substantial indebtedness incurred to finance the consummation of the proposed merger; and
- with respect to the InfrastruX Energy Services joint venture, the amount of time the Commission takes to review the transaction and the results of such review.

Any forward-looking statement speaks only as of the date on which it is made, and TXU Corp. undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which it is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for TXU Corp. to predict all of them; nor can TXU Corp. assess the impact of each such factor or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement.