

# 2003 Statistical Summary



## ABOUT THE COMPANY

TXU is a major energy company with operations in North America. TXU manages a diverse energy portfolio with a strategic mix of over \$31 billion of assets. TXU's business model for competitive markets integrates generation, trading and marketing operations. The regulated electric delivery business, comprised of distribution and transmission assets, complements the competitive operations, delivering stable earnings and cash flow for TXU stakeholders. The electric delivery business uses its asset management skills developed over its hundred year history to provide reliable electric delivery to nearly 3 millions points of delivery.

In its primary market of Texas, TXU's portfolio includes 18,500 megawatts of generation and additional contracted capacity with a fuel mix of coal/lignite, natural gas/oil, nuclear power and wind. TXU serves 2.6 million competitive electric customers in Texas where it is the leading energy retailer.

Recently, TXU has agreed to sell its energy business in Australia, TXU Australia, and has announced its intent to sell TXU Gas, its largely regulated natural gas transmission and distribution business in Texas.

## THIS SUMMARY

The consolidated financial data and statistics in this summary reflect the financial position and operating results of TXU through 2003. While certain information represents TXU and its consolidated subsidiaries, the primary focus of

this summary is TXU's operating and financial performance.

This summary is only intended to provide limited supplemental operational and statistical information. Its contents do not constitute a complete set of financial statements prepared in accordance with generally accepted accounting principles. Accordingly, this summary is qualified in its entirety by reference to, and should be read in conjunction with, and not in lieu of, the companies' reports, including financial statements and their accompanying notes, on file with the Securities and Exchange Commission.

Independent auditors have not audited all of the financial and operating statements. This summary has been prepared primarily for security analysts and investors in the hope that it will serve as a convenient and useful resource. The format of this summary may change in the future as we continue to try to meet the needs of our investors. The company does not undertake to update any of this information in this summary.

This summary is not intended for use in connection with any sale, offer to sell, or solicitation of any offer to buy any securities of TXU Corp. or its subsidiaries. Inquiries concerning this summary should be directed to Investor Relations:

Tim Hogan                      Rose Blessing  
214-812-4641                      214-812-2498

Laura Conn  
214-812-3127

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**TXU CORP. AND SUBSIDIARIES**  
**STATEMENTS OF CONSOLIDATED INCOME**

	Year Ended December 31,		
	2003	2002	2001
	(\$ millions, except per share amounts)		
Operating revenues.....	\$11,008	\$ 9,896	\$ 9,890
Costs and expenses:			
Cost of energy sold and delivery fees .....	4,947	4,087	4,134
Operating costs .....	1,665	1,592	1,490
Depreciation and amortization, other than goodwill.....	886	868	781
Selling, general and administrative expenses .....	1,108	1,213	940
Franchise and revenue-based taxes .....	456	478	529
Other income .....	(82)	(51)	(46)
Other deductions.....	46	577	331
Interest income .....	(44)	(31)	(82)
Interest expense and related charges .....	975	882	965
Goodwill amortization.....	—	—	43
Total costs and expenses.....	<u>9,957</u>	<u>9,615</u>	<u>9,085</u>
Income from continuing operations before income taxes, extraordinary loss and cumulative effect of changes in accounting principles.....	1,051	281	805
Income tax expense .....	<u>314</u>	<u>99</u>	<u>236</u>
Income from continuing operations before extraordinary loss and cumulative effect of changes in accounting principles .....	737	182	569
Income (loss) from discontinued operations, net of tax effect .....	(97)	(4,258)	165
Extraordinary loss, net of tax effect .....	—	(134)	(57)
Cumulative effect of changes in accounting principles, net of tax benefit .....	<u>(58)</u>	<u>—</u>	<u>—</u>
Net income (loss) before preference stock dividends.....	582	(4,210)	677
Preference stock dividends .....	<u>22</u>	<u>22</u>	<u>22</u>
Net income (loss) available for common stock .....	<u>\$ 560</u>	<u>\$(4,232)</u>	<u>\$ 655</u>
Average shares of common stock outstanding (millions):			
Basic .....	322	278	259
Diluted .....	379	278	259
Per share of common stock— Basic:			
Income from continuing operations before extraordinary loss and cumulative effect of changes in accounting principles .....	\$ 2.22	\$ 0.58	\$ 2.11
Income (loss) from discontinued operations, net of tax effect .....	\$ (.30)	\$(15.33)	\$ 0.63
Extraordinary loss, net of tax effect .....	\$ —	\$ (0.48)	\$ (0.22)
Cumulative effect of changes in accounting principles, net of tax benefit .....	\$ (0.18)	\$ —	\$ —
Net income (loss) available for common stock .....	\$ 1.74	\$(15.23)	\$ 2.52
Per share of common stock— Diluted:			
Income from continuing operations before extraordinary loss and cumulative effect of changes in accounting principles .....	\$ 2.03	\$ 0.58	\$ 2.11
Income (loss) from discontinued operations, net of tax effect .....	\$ (.26)	\$(15.33)	\$ .63
Extraordinary loss, net of tax effect .....	\$ —	\$ (0.48)	\$ (0.22)
Cumulative effect of changes in accounting principles, net of tax benefit .....	\$ (0.15)	\$ —	\$ —
Net income (loss) available for common stock .....	\$ 1.62	\$(15.23)	\$ 2.52
Dividends declared.....	\$ 0.50	\$ 1.925	\$ 2.40

## TXU CORP. AND SUBSIDIARIES CONSOLIDATED BALANCE SHEETS

	December 31,	
	2003	2002
	(\$ millions)	
<b>ASSETS</b>		
Current assets		
Cash and cash equivalents.....	\$ 875	\$ 1,573
Restricted cash .....	12	210
Accounts receivable — trade.....	1,369	1,670
Income taxes receivable.....	—	488
Inventories .....	599	545
Commodity contract assets .....	959	1,298
Assets of telecommunications holdings company .....	110	—
Other current assets.....	<u>333</u>	<u>348</u>
Total current assets.....	<u>4,257</u>	<u>6,132</u>
Investments		
Restricted cash .....	582	96
Other investments.....	705	724
Property, plant and equipment — net .....	20,920	19,981
Goodwill.....	1,829	1,588
Regulatory assets — net.....	1,837	1,654
Commodity contract assets .....	362	657
Cash flow hedges and other derivative assets .....	123	150
Other noncurrent assets.....	411	328
Assets held for sale.....	<u>660</u>	<u>95</u>
Total assets .....	<u>\$31,686</u>	<u>\$31,405</u>
<b>LIABILITIES, PREFERRED SECURITIES OF SUBSIDIARIES AND SHAREHOLDERS' EQUITY</b>		
Current liabilities		
Notes payable		
Commercial paper.....	\$ 39	\$ 18
Banks.....	58	2,306
Long-term debt due currently .....	677	958
Accounts payable — trade.....	1,042	1,029
Commodity contract liabilities.....	913	1,138
Liabilities of telecommunications holding company.....	603	—
Other current liabilities .....	<u>1,339</u>	<u>1,293</u>
Total current liabilities .....	<u>4,671</u>	<u>6,742</u>
Accumulated deferred income taxes.....	3,939	3,607
Investment tax credits .....	430	453
Commodity contract liabilities.....	318	520
Cash flow hedges and other derivative liabilities .....	267	220
Long-term debt held by subsidiary trusts .....	546	546
All other long-term debt, less amounts due currently.....	12,324	11,593
Other noncurrent liabilities and deferred credits .....	2,370	2,400
Liabilities held for sale.....	<u>143</u>	<u>47</u>
Total liabilities.....	25,008	26,128
Preferred securities of subsidiaries .....	759	211
Contingencies		
Shareholders' equity.....	<u>5,919</u>	<u>5,066</u>
Total liabilities, preferred securities of subsidiaries and shareholders' equity .....	<u>\$31,686</u>	<u>\$31,405</u>

**TXU CORP. AND SUBSIDIARIES**  
**STATEMENTS OF CONSOLIDATED CASH FLOWS**

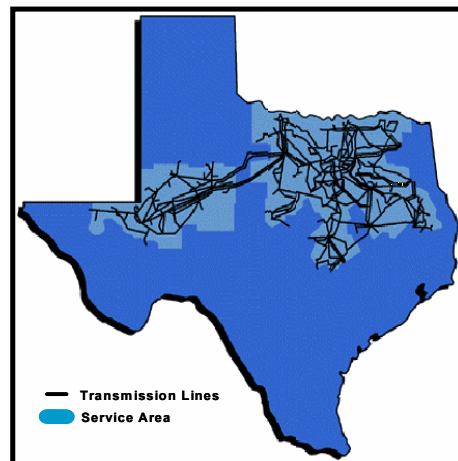
	Year Ended December 31,		
	2003	2002	2001
	(\$ millions)		
Cash flows — operating activities			
Income from continuing operations before extraordinary loss and cumulative effect of changes in accounting principles.....	\$ 737	\$ 182	\$ 569
Adjustments to reconcile income from continuing operations before extraordinary loss and cumulative effect of changes in accounting principles to cash provided by operating activities:			
Depreciation and amortization.....	959	947	1,022
Deferred income taxes and investment tax credits — net.....	10	65	(88)
Losses on early extinguishment of debt.....	—	63	149
Net gains from sale of assets.....	(43)	(31)	(1)
Reduction of revenues for earnings in excess of regulatory earnings cap.....	—	—	40
Net effect of unrealized mark-to-market valuations of commodity contracts.....	128	108	(323)
Net equity loss from unconsolidated affiliates and joint ventures.....	17	255	53
Asset impairments charge.....	—	237	—
Retail clawback accrual increase (decrease).....	(12)	185	—
Reduction in regulatory liability.....	(132)	(151)	—
Over/(under) recovery of gas costs.....	52	(8)	551
Changes in operating assets and liabilities:			
Accounts receivable — trade.....	367	(515)	489
Inventories.....	(67)	(54)	(49)
Accounts payable — trade.....	(5)	181	(835)
Commodity contract assets and liabilities.....	25	(44)	(27)
Margin deposits.....	25	—	227
Other assets.....	382	(106)	79
Other liabilities.....	355	34	14
Cash provided by operating activities.....	<u>2,798</u>	<u>1,348</u>	<u>1,870</u>
Cash flows — financing activities			
Issuances of securities:			
Equity-linked debt securities.....	—	440	1,000
Exchangeable subordinated notes.....	—	750	—
Other long-term debt.....	3,245	3,377	4,954
Common stock.....	23	1,274	354
Retirements/repurchases of securities:			
Long-term debt.....	(2,736)	(3,595)	(4,648)
Preferred securities of subsidiaries.....	(98)	—	—
Securities of unconsolidated subsidiary trusts.....	—	—	(837)
Common stock.....	—	—	(44)
Change in notes payable:			
Commercial paper.....	13	(844)	(1,035)
Banks.....	(2,252)	1,243	615
Cash dividends paid:			
Common stock.....	(160)	(652)	(621)
Preference stock.....	(22)	(22)	(22)
Redemption deposits applied to debt retirements.....	210	(210)	—
Debt premium, discount, financing and reacquisition expenses.....	(41)	(283)	(232)
Cash provided by (used in) financing activities.....	<u>(1,818)</u>	<u>1,478</u>	<u>(516)</u>
Cash flows — investing activities			
Capital expenditures.....	(956)	(1,003)	(1,243)
Acquisition of businesses.....	(150)	(36)	—
Proceeds from sale of assets.....	24	449	26
Nuclear fuel.....	(44)	(51)	(38)
Investment in collateral trust.....	(525)	—	—
Other.....	2	(210)	58
Cash used in investing activities.....	<u>(1,649)</u>	<u>(851)</u>	<u>(1,197)</u>
Effect of exchange rate changes on cash and cash equivalents.....	8	(13)	2
Cash provided (used by) discontinued operations.....	(37)	(605)	8
Net change in cash and cash equivalents.....	(698)	1,357	167
Cash and cash equivalents — beginning balance.....	<u>1,573</u>	<u>216</u>	<u>49</u>
Cash and cash equivalents — ending balance.....	<u>\$ 875</u>	<u>\$ 1,573</u>	<u>\$ 216</u>

## OPERATING STATISTICS – ELECTRIC DELIVERY

TXU’s electric delivery business<sup>(1)</sup> (Electric Delivery) operates the largest, best-performing electric delivery company in Texas, with outstanding efficiency and reliability. It delivers energy safely and dependably, serving nearly 3 million electric points of delivery and operates in a state with a forward-looking regulatory environment and highly diverse economy.

### Description of TXU’s Electric Delivery Business

TXU’s electric delivery business owns and operates 98,286 miles of electric distribution lines and 14,180 miles of electric transmission lines. The operating assets are located principally in the north-central, eastern and western parts of Texas. Electric Delivery operates within the ERCOT system. ERCOT is an intrastate network of investor-owned entities, cooperatives, public entities, non-utility generators and power marketers.



### Electric Distribution

TXU’s distribution business is responsible for the overall safe and efficient operation of distribution facilities, including power delivery, power quality and system reliability. The electricity distribution business owns, manages, constructs, maintains and operates the distribution system within its certificated service area. Over the past five years, the number of distribution premises served has been growing an average of 2% per year.

### Distribution Facts

Item	2003	2002	2001	2000	1999
Transformer Capacity (MVA)	47,991	46,722	45,503	43,949	42,201
Circuit Miles of Line	98,286	96,847	95,793	94,644	91,635
Count of Load Serving Substations	795	791	789	752	705
Distribution Feeders	2,944	2,914	2,897	2,861	2,829
Electric Delivery Owned Poles <sup>(a)</sup>	1,886,284	1,877,954	1,893,714	1,885,040	1,822,356
Third Party Poles <sup>(b)</sup>	297,188	296,218	270,649	270,620	260,243

<sup>(a)</sup> 30K poles sold during 2000 to 2002 timeframe

<sup>(b)</sup> Count of third party poles contacted

TXU’s distribution system receives electricity from the transmission system through substations and distributes electricity to end users and wholesale customers through 2,944 distribution feeders.

### Electric Transmission

TXU’s electricity transmission business is responsible for the safe and reliable operations of its transmission network and substations. These responsibilities consist of the construction and maintenance of transmission facilities and substations and the monitoring, controlling and dispatching of high-voltage electricity in coordination with ERCOT.

<sup>(1)</sup> TXU’s electric delivery business operated under the name ‘Oncor Electric Delivery’ during 2003 and 2002.

## OPERATING STATISTICS – ELECTRIC DELIVERY

### Transmission Facts

Item	2003	2002	2001	2000	1999
Transformer Capacity (MVA)	70,890	68,385	68,089	66,893	65,335
Circuit Miles of Line	14,180	14,137	14,010	13,815	13,732
Count of Substations, Switching Stations and Plant					
Switchyards	950	946	941	935	931
Transmission Circuit Breakers	5,749	5,633	5,569	5,466	5,392
Interconnection to Generation Facilities	43	41	38	34	32
Interconnection to Other Transmission Providers	241	200	217	211	200

The transmission business participates with ERCOT and other member utilities to plan, design, construct, and operate new transmission lines, with regulatory approval, necessary to maintain reliability, increase bulk power transfer capability and to minimize limitations and constraints on the ERCOT transmission grid.

### Key Operational Metrics

Metric	2003	2002	2001	2000	1999
Non-Storm SAIDI (minutes)	74.15	90.36	81.77	87.46	75.40
Non-Storm SAIFI (frequency) <sup>(1)</sup>	1.17	1.38	1.23	1.37	1.20
Non-Storm CAIDI (minutes)	63.38	65.48	66.48	63.84	62.83
Meter Reading Accuracy	99.885%	99.982%	99.909%	99.900%	99.929%
Lost Workday Incident Rate	1.71	1.89	2.41	2.32	2.08
Regulatory Complaints <sup>(2)</sup>	367	394	852	297	361

<sup>(1)</sup> Based on all outages greater than one minute in duration

<sup>(2)</sup> Complaints spiked in 2001 due to implementation of the pilot prior to the opening of the Texas electricity market to competition, and increased public awareness of the PUC's involvement in regulating electric utilities.

### Selected Financial Metrics

(\$ millions)	2003	2002	2001 <sup>(1)</sup>	2000 <sup>(1)</sup>	1999 <sup>(1)</sup>
Total Operating Revenues	2,087	1,994	2,314	2,081	1,931
Total Operating Expenses	1,565	1,517	1,820	1,597	1,444
Net Income Before Extraordinary Items	258	245	228	226	223
Extraordinary Items <sup>(2)</sup>		(123)			
Net Income After Extraordinary Items	258	122	228	226	223
Property, Plant & Equipment – Net	6,333	6,056	5,802	5,445	5,166
Capital Expenditures	543	513	635	517	489
Capitalization Ratios					
Long-term debt, less amounts due currently	58.2%	60.6%	54.9%	52.1%	48.4%
Shareholder Equity	41.8%	39.4%	45.1%	47.9%	51.6%

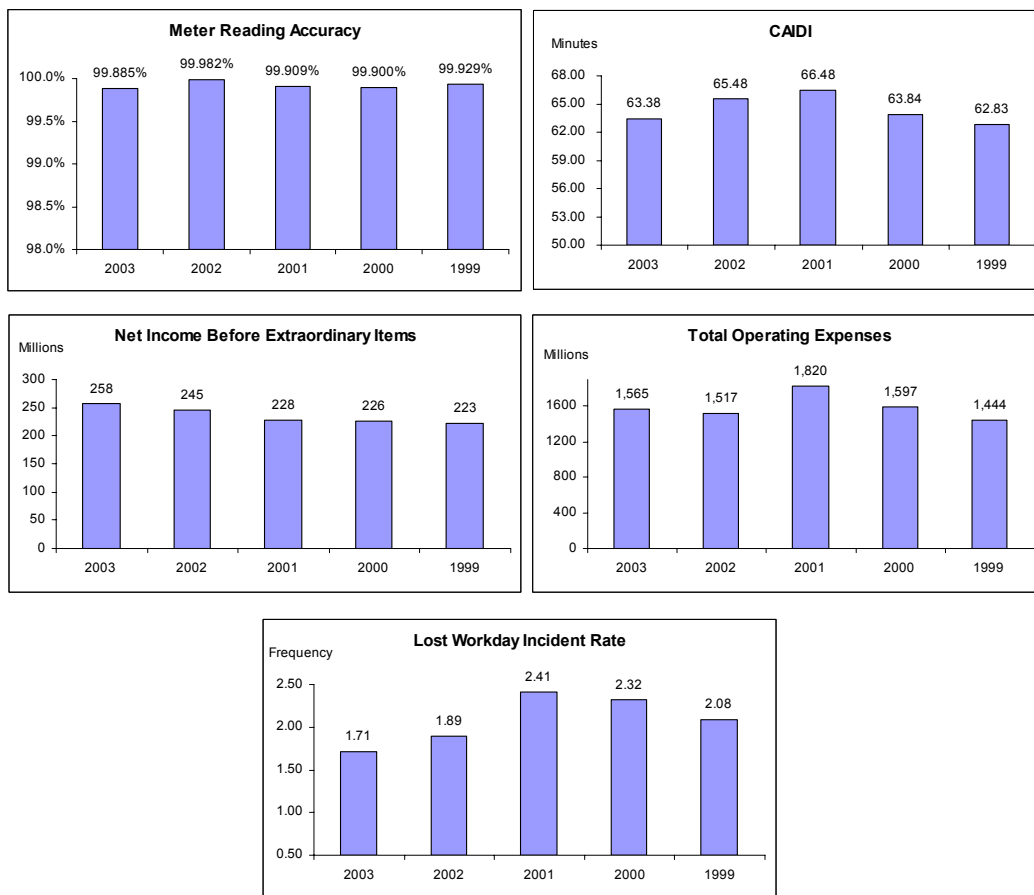
<sup>(1)</sup> The 1999, 2000 and 2001 financial information for Oncor includes information derived from the historical financial statements of TXU Electric. Reasonable allocation methodologies were used to unbundle the financial statements of TXU Electric between its generation, retail and T&D operations. Allocation of revenues reflected consideration of return on invested capital, which continues to be regulated for the T&D operations. TXU Electric maintained expense accounts for each of its functional operations. Costs of O&M, plant and equipment and depreciation, as well as other assets and liabilities were specifically identified by component and function and then disaggregated. Interest and other financing costs were determined based upon debt allocated. Allocations reflected in the financial information for 1999, 2000 and 2001 did not necessarily result in amounts reported in individual line items that are comparable to actual results in 2002. Had the unbundled T&D operations of US Holdings actually existed as a separate legal entity, its results of operations could have differed materially from those included in the historical financial statements of TXU Electric.

<sup>(2)</sup> The extraordinary loss in 2002 of \$123 million (net of income tax benefit of \$66 million) was a charge to write-down generation related regulatory assets related to securitization bonds to be issued in the future in accordance with the Settlement Plan. The regulatory asset write-down reflects the difference between the carrying value of the regulatory asset and the projected cash flows associated with the securitization bonds expected to be recovered through higher electricity delivery rates. This difference reflects the decline in interest rates.

## OPERATING STATISTICS – ELECTRIC DELIVERY

### Electric Delivery Performance Highlights

Electric Delivery has consistently delivered both operationally and financially over the last 5 years, and has achieved excellence in safety and service performance.



### Service Performance Statistics

Electric Delivery finished 2003 as the best performing transmission and distribution service provider (TDSP) by performing at or above market average in 6 out of 7 key ERCOT service categories. Electric Delivery had 47% of the total ERCOT market transactions.

Metric	ERCOT Report Market Average	TXU
Scheduling of Switches	98.8%	98.8%
Scheduling of Move-ins	96.5%	96.3%
On Schedule Completion of Switches	84.2%	94.0%
On Schedule Completion of Move-ins	73.8%	78.1%
Providing Historical Usage	89.2%	95.1%
Loading of IDR Metering Data	98.5%	99.0%
Loading of NIDR Metering Data	97.5%	98.8%

## OPERATING STATISTICS – ELECTRIC DELIVERY

### Regulatory Environment

TXU's electric delivery business is subject to regulation by Texas authorities. Electric Delivery provides delivery services to Retail Electric Providers (REPS) who sell electricity to retail customers; consequently, the electric delivery business has no commodity supply or price risk. Electric Delivery operates in a favorable regulatory environment, as evidenced by a regulatory provision that allows annual updates of transmission rates to reflect changes in invested capital. This provision encourages investment in the transmission system to help ensure reliability and efficiency by allowing for timely recovery and return on new transmission investments.

### General Rate Information

Electric Delivery has an authorized return on equity of 11.25%. There is currently no scheduled rate case. Earnings Monitoring Reports are filed annually for review with the PUC.

### Transmission Cost of Service (TCOS) and Transmission Cost Recovery Factor (TCRF)

ERCOT transmission service providers (TSPs) recover their TCOS through a network transmission service rate approved by the Public Utility Commission of Texas (PUCT). ERCOT TSPs bill their wholesale network transmission service charges to ERCOT distribution utilities, by applying their approved wholesale transmission rates to the distribution utilities' average loads for the prior summer<sup>(1)</sup>. Distribution utilities are billed for wholesale transmission service by all ERCOT TSPs. Distribution utilities<sup>(2)</sup> recover these transmission fees by billing the retail electric providers a base retail transmission charge. In the Utility Cost of Service (UCOS) cases, the distribution utilities established base retail transmission charges by rate class. These rates are in addition to the base retail distribution system wires charges and other non-bypassable charges that are billed to retail electric providers.

In the latest wholesale transmission rulemaking, the Commission approved a new rule section, Distribution Service Provider TCRF. The purpose of this rule section is to allow distribution service providers to pass through wholesale transmission rate increases without the need for a distribution utility rate case. The TCRF rule allows distribution utilities to update the TCRF on March 1 and September 1 each year. The TCRF charges are billed in addition to the base retail transmission wires charges.

(1) The load for a distribution utility is the average demand at the time of the ERCOT peak for the months of June, July, August, and September.

(2) Investor Owned Utilities (IOU's) and other entities participating in customer choice.

### Wire Rate Charges

As shown in the chart below, Electric Delivery has the lowest wires rate in the State of Texas.

<b>Operational Wires Rates Comparison – Residential (as of March 1, 2004)</b>					
<b>Charge</b>	<b>TXU</b>	<b>Centerpoint</b>	<b>AEP Central</b>	<b>AEP North</b>	<b>TNMP</b>
Customer Charge	\$ 2.74/cust/month	\$ 2.39/cust/month	\$ 2.58/cust/month	\$ 4.58/cust/month	\$ 0.33/cust/month
Metering Charge	\$ 2.21/cust/month	\$ 1.91/cust/month	\$ 2.38/cust/month	\$ 4.78/cust/month	\$ 3.58/cust/month
Merger Savings/Rate Reduction Charge	\$ 0.00/cust/month	\$ 0.00/cust/month	(\$ 0.28)/cust/month	(\$ 0.48)/cust/month	\$ 0.00/cust/month
<b>Subtotal, Fixed Charges</b>	<b>\$ 4.95/cust/month</b>	<b>\$ 4.30/cust/month</b>	<b>\$ 4.68/cust/month</b>	<b>\$ 8.88/cust/month</b>	<b>\$ 3.91/cust/month</b>
Distribution System Charge	\$ 0.014070/kWh	\$ 0.018870/kWh	\$ 0.015628/kWh	\$ 0.019863/kWh	\$ 0.017291/kWh
Transmission System Charge	\$ 0.004493/kWh	\$ 0.004310/kWh	\$ 0.003712/kWh	\$ 0.004638/kWh	\$ 0.004150/kWh
Transmission Cost Recovery Factor	\$ 0.000501/kWh	\$ 0.000485/kWh	\$ 0.000449/kWh	\$ 0.000650/kWh	\$ 0.000535/kWh
<b>Subtotal, Basic Wires Charges</b>	<b>\$ 0.029064/kWh</b>	<b>\$ 0.023665/kWh</b>	<b>\$ 0.019789/kWh</b>	<b>\$ 0.025151/kWh</b>	<b>\$ 0.021976/kWh</b>
<b>Total Wires Charge for 1,000 kWh</b>	<b>\$ 24.01</b>	<b>\$ 27.97</b>	<b>\$ 24.27</b>	<b>\$ 34.03</b>	<b>\$ 25.89</b>
<b>Total Wires Charge for 1,300 kWh</b>	<b>\$ 29.73</b>	<b>\$ 35.06</b>	<b>\$ 30.41</b>	<b>\$ 41.58</b>	<b>\$ 32.48</b>

Electric Delivery's average residential consumption for 2003 was about 1,300 kWh. Other non-operating charges, including System Benefit Fund, Nuclear Decommissioning Charge, Excess Mitigation Credit, Retail Clawback Credit, Transition Charge on securitized regulatory assets, and Merger Savings/Rate Reduction Riders, have not been included in this comparison.

### Rate Base

For the period ending December 31, 2003, Electric Delivery Adjusted Total Invested Capital<sup>(3)</sup> is \$5,381,055,975, as compared to our 2002 Adjusted Total Invested Capital of \$5,233,768,154.

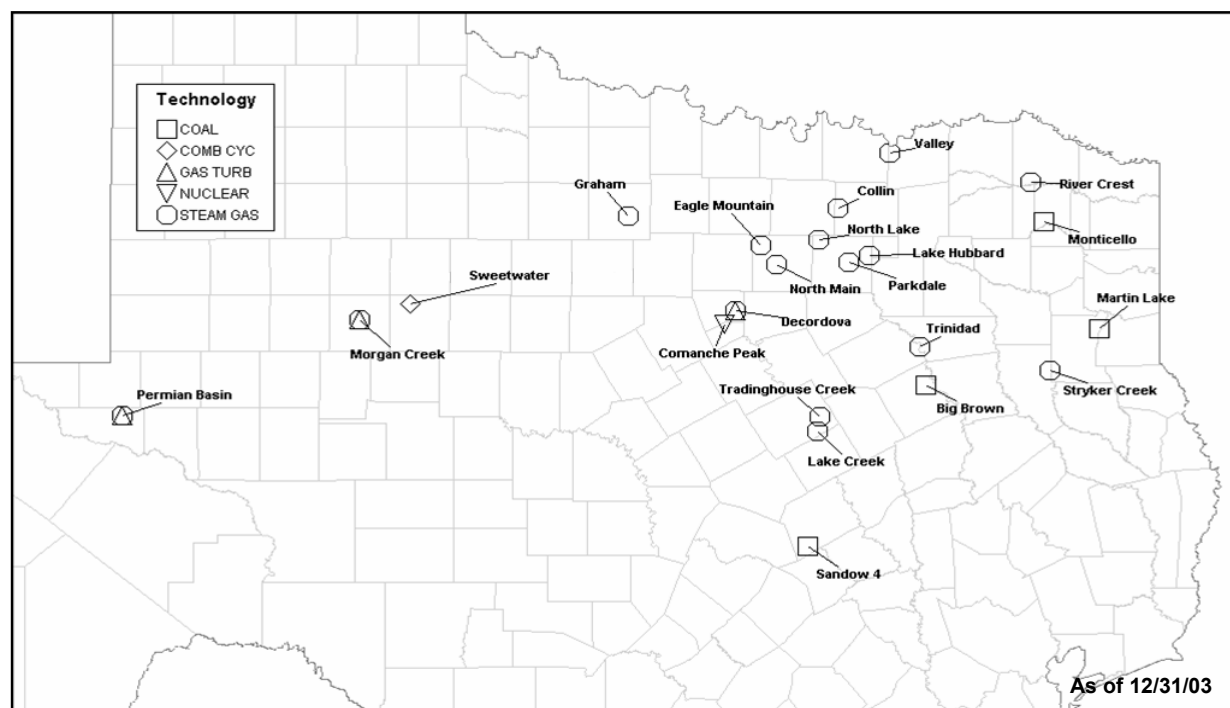
(3) Adjusted Total Invested Capital = Total Invested Capital – [Construction Work in Progress + Plant Held for Future Use]

## OPERATING STATISTICS – POWER

TXU Energy's generating facilities provide TXU Energy with the capability to supply a significant portion of the wholesale electricity market demand in Texas, particularly in the North Texas market, at competitive production costs. As part of TXU Energy's integrated business portfolio, much of the low cost nuclear fueled and lignite/coal-fired (base load) generation is available to supply the electricity demands of its retail customers and other competitive retail electric providers. The generating fleet in Texas consists of 22 owned or leased plants with generating capacity fueled as follows: 2,300 MW nuclear; 5,837 MW coal/lignite; and 10,881 MW gas/oil. In addition, TXU Energy has a cogeneration and wholesale energy production business in New Jersey that includes a 122 megawatt (MW) combined-cycle electricity production facility and various contracts, including electric supply and gas transportation agreements.

### Generating Plant Locations – Texas

	Nuclear	Lignite/Coal	Gas/Oil	Total
Number of Generating Units	2	9	48	59
2003 Installed Capacity (MWs)	2,300	5,837	10,881	19,018
Annual Generation (3 year average MWHs)	17,550,231	40,854,668	20,228,018	78,632,917



## OPERATING STATISTICS – POWER

### Unit Statistics and Information – Texas

Plant	Unit	Fuel type	Type	Year in Service <sup>(3)</sup>	County	Installed Capacity
Comanche Peak	1	Nuclear	Baseload	1990	Somervell	1,150
Comanche Peak	2	Nuclear	Baseload	1993	Somervell	1,150
<b>Subtotal</b>						<b>2,300</b>
Big Brown	1	Lignite/Coal	Baseload	1971	Freestone	575
Big Brown	2	Lignite/Coal	Baseload	1972	Freestone	575
Monticello	1	Lignite/Coal	Baseload	1974	Titus	565
Monticello	2	Lignite/Coal	Baseload	1975	Titus	565
Monticello	3	Lignite/Coal	Baseload	1978	Titus	750
Martin Lake	1	Lignite/Coal	Baseload	1977	Rusk	750
Martin Lake	2	Lignite/Coal	Baseload	1978	Rusk	750
Martin Lake	3	Lignite/Coal	Baseload	1979	Rusk	750
Sandow	4	Lignite/Coal	Baseload	1981	Milam	557
<b>Subtotal</b>						<b>5,837</b>
Collin (M)	1	Gas/Oil	Gas - Cycling	1955	Collin	153
DeCordova	1	Gas/Oil	Gas - Intermediate	1975	Hood	818
DeCordova 4 CT's <sup>(1)</sup>		Gas/Oil	Gas - Peaking	1990	Hood	260
Eagle Mountain (M)	1	Gas/Oil	Gas - Cycling	1954	Tarrant	115
Eagle Mountain (M)	2	Gas/Oil	Gas - Cycling	1956	Tarrant	175
Eagle Mountain (M)	3	Gas/Oil	Gas - Cycling	1971	Tarrant	375
Graham	1	Gas/Oil	Gas - Cycling	1960	Young	240
Graham	2	Gas/Oil	Gas - Intermediate	1969	Young	390
Lake Creek	1	Gas/Oil	Gas - Cycling	1953	McLennan	87
Lake Creek	2	Gas/Oil	Gas - Cycling	1959	McLennan	230
Lake Hubbard	1	Gas/Oil	Gas - Cycling	1970	Dallas	393
Lake Hubbard	2	Gas/Oil	Gas - Intermediate	1973	Dallas	528
Morgan Creek (R)	2	Gas/Oil	Gas - Cycling	1950	Mitchell	22
Morgan Creek (R)	3	Gas/Oil	Gas - Cycling	1952	Mitchell	44
Morgan Creek (R)	4	Gas/Oil	Gas - Cycling	1954	Mitchell	70
Morgan Creek	5	Gas/Oil	Gas - Cycling	1959	Mitchell	175
Morgan Creek	6	Gas/Oil	Gas - Intermediate	1966	Mitchell	511
Morgan Creek 6 CT's <sup>(1)</sup>		Gas/Oil	Gas - Peaking	1988	Mitchell	390
North Lake	1	Gas/Oil	Gas - Cycling	1959	Dallas	175
North Lake	2	Gas/Oil	Gas - Cycling	1961	Dallas	175
North Lake	3	Gas/Oil	Gas - Cycling	1964	Dallas	365
North Main (R)	4	Gas/Oil	Gas - Cycling	1952	Tarrant	80
Parkdale (P)	1	Gas/Oil	Gas - Cycling	1953	Dallas	87
Parkdale (P)	2	Gas/Oil	Gas - Cycling	1955	Dallas	115
Parkdale (P)	3	Gas/Oil	Gas - Cycling	1957	Dallas	125
Permian Basin	5	Gas/Oil	Gas - Cycling	1959	Ward	115
Permian Basin	6	Gas/Oil	Gas - Intermediate	1973	Ward	540
Permian Basin 5 CT's <sup>(1)</sup>		Gas/Oil	Gas - Peaking	1990	Ward	325
River Crest (R)	6	Gas/Oil	Gas - Cycling	1954	Red River	110
Stryker Creek	1	Gas/Oil	Gas - Cycling	1958	Cherokee	175
Stryker Creek	2	Gas/Oil	Gas - Intermediate	1965	Cherokee	500
Tradinghouse	1	Gas/Oil	Gas - Intermediate	1970	McLennan	565
Tradinghouse	2	Gas/Oil	Gas - Intermediate	1972	McLennan	818
Valley	1	Gas/Oil	Gas - Cycling	1962	Fannin	175
Valley	2	Gas/Oil	Gas - Intermediate	1967	Fannin	550
Valley	3	Gas/Oil	Gas - Cycling	1971	Fannin	390
Trinidad	6	Gas/Oil	Gas - Cycling	1965	Henderson	240
Sweetwater	4	Gas/Oil	Gas - Cycling	1989	Nolan	85
Sweetwater 3 CT's <sup>(1)</sup>		Gas/Oil	Gas - Peaking	1989	Nolan	175
Diesels <sup>(2)</sup>						20
<b>Subtotal</b>						<b>10,881</b>
<b>Total</b>						<b>19,018</b>

<sup>(1)</sup> CT – Combustion Turbine

<sup>(2)</sup> Diesels located at Lake Creek (3), Stryker Creek (5) and Trinidad (2)

<sup>(3)</sup> Average useful lives: nuclear (60 years), lignite (50 years), gas (51 years), and gas CT's (27 years)

(R) – Retired, subject to ERCOT Review

(M) – Mothballed, subject to ERCOT Review

(P) – Retirement pending subject to ERCOT Review

## OPERATING STATISTICS – POWER

### Nuclear Plant Statistics

	CPSES Unit 1	CPSES Unit 2
Commercial Operation Date	August, 1990	August, 1993
License Expiration Date	February, 2030	February, 2033
Architect/Engineer	Gibbs & Hill	Gibbs & Hill
Reactor Manufacturer	Westinghouse	Westinghouse
Reactor Type	PWR	PWR
Turbine Generator Manufacturer	Siemens	Siemens
Maximum Dependable Capacity (MW)	1,150	1,150
Refueling Data		
Last Date	March 27, 2004	October 4, 2003
# of Days	38	25
Next Scheduled Refueling	Fall, 2005	Spring, 2005

## OPERATING STATISTICS – POWER

### Net Generation (MWh) – Texas<sup>(1)</sup>

Plant	Unit	2003	2002	2001	2000	1999
Comanche Peak	1	9,625,953	7,785,265	8,444,318	9,619,797	8,601,515
Comanche Peak	2	8,123,390	8,793,819	9,877,947	8,868,045	8,756,024
<b>Subtotal</b>		<b>17,749,343</b>	<b>16,579,084</b>	<b>18,322,265</b>	<b>18,487,842</b>	<b>17,357,539</b>
Big Brown	1	4,587,394	4,362,128	3,733,166	4,230,742	2,885,836
Big Brown	2	3,875,181	3,558,722	3,539,669	4,314,241	3,319,625
Monticello	1	4,134,558	3,711,998	3,646,758	4,143,518	4,113,329
Monticello	2	3,704,847	4,030,192	4,024,631	3,478,659	3,615,989
Monticello	3	5,666,922	5,385,687	4,904,882	4,748,085	5,465,416
Martin Lake	1	4,847,711	5,148,997	5,104,000	5,596,189	5,419,028
Martin Lake	2	5,781,564	5,079,555	4,812,971	5,433,020	5,696,517
Martin Lake	3	5,855,120	4,596,454	5,305,204	5,492,880	5,672,160
Sandow	4	4,787,459	3,943,323	4,434,912	3,556,611	4,656,761
<b>Subtotal</b>		<b>43,240,756</b>	<b>39,817,056</b>	<b>39,506,193</b>	<b>40,993,945</b>	<b>40,844,661</b>
Collin	1	98,879	74,572	191,886	297,464	180,056
DeCordova	1	1,414,916	2,974,511	3,338,979	3,911,118	4,036,546
DeCordova CT's		54,144	68,125	102,052	181,854	117,083
Eagle Mountain	1	57,865	101,874	74,725	148,244	85,047
Eagle Mountain	2	79,830	193,175	197,646	256,133	290,421
Eagle Mountain	3	479,676	526,756	317,572	531,411	478,667
Graham	1	186,907	564,898	452,737	931,078	901,319
Graham	2	575,707	651,729	803,227	1,362,246	1,479,596
Lake Creek	1	1,858	29,460	64,960	208,005	156,743
Lake Creek	2	83,025	281,967	472,369	691,554	601,235
Lake Hubbard	1	400,926	414,224	462,944	802,460	671,997
Lake Hubbard	2	1,235,607	1,270,631	1,584,785	1,863,522	1,903,506
Morgan Creek	2	(1,561)	(1,478)	1,492	22,510	17,249
Morgan Creek	3	(626)	(719)	3,812	16,203	36,035
Morgan Creek	4	(1,569)	6,343	37,413	127,195	85,320
Morgan Creek	5	121,329	232,540	365,920	568,993	538,094
Morgan Creek	6	629,540	842,029	1,979,522	2,687,161	2,445,533
Morgan Creek CT's		38,492	43,183	68,387	174,584	123,076
North Lake	1	226,630	352,048	339,274	337,409	429,073
North Lake	2	167,805	309,276	378,195	461,831	353,470
North Lake	3	479,022	610,546	608,939	1,120,695	849,038
North Main	4	(832)	56,863	14,775	145,506	67,645
Parkdale	1	12,203	62,470	50,900	141,342	91,393
Parkdale	2	21,096	99,219	81,301	209,655	130,188
Parkdale	3	30,029	124,749	120,699	263,059	160,568
Permian Basin	5	40,019	95,770	221,266	321,259	267,696
Permian Basin	6	1,802,737	2,136,339	2,367,173	2,607,556	2,954,514
Permian Basin CT's		35,266	31,412	62,367	165,561	71,951
River Crest	6	(833)	(584)	8,348	183,042	120,442
Stryker Creek	1	72,005	56,704	312,232	449,959	372,617
Stryker Creek	2	1,019,363	1,058,502	1,417,285	1,921,490	2,136,540
Tradinghouse	1	552,739	1,483,468	1,520,938	1,806,095	2,180,047
Tradinghouse	2	1,548,337	1,578,856	3,568,742	3,595,258	3,734,643
Valley	1	141,253	192,241	327,436	496,770	402,496
Valley	2	325,731	1,236,428	1,668,866	2,086,165	2,356,661
Valley	3	95,422	199,461	366,490	610,776	435,352
Trinidad	6	144,262	218,517	415,436	397,010	479,822
Sweetwater	4	244,802	153,002	–	–	–
Sweetwater CT	1	65,316	85,440	–	–	–
Sweetwater CT	2	290,888	39,504	–	–	–
Sweetwater CT	3	330,777	279,435	–	–	–
<b>Subtotal</b>		<b>13,098,982</b>	<b>18,733,486</b>	<b>24,371,090</b>	<b>32,102,173</b>	<b>31,741,679</b>
<b>Total</b>		<b>74,089,081</b>	<b>75,129,626</b>	<b>82,199,548</b>	<b>91,583,960</b>	<b>89,943,879</b>

<sup>(1)</sup> Excludes divested units.

## OPERATING STATISTICS – POWER

### Unit Capacity Factors (%) – Texas

Plant	Unit	2003	2002	2001	2000	1999
Comanche Peak	1	95.6	77.2	83.8	95.2	85.4
Comanche Peak	2	80.6	87.2	98.1	87.7	86.9
Big Brown	1	91.1	86.6	74.1	83.8	57.3
Big Brown	2	76.9	70.7	70.3	85.4	65.9
Monticello	1	83.5	75.0	73.7	83.5	83.1
Monticello	2	74.9	81.4	81.3	70.1	73.1
Monticello	3	86.3	82.0	74.7	72.1	83.2
Martin Lake	1	73.8	78.4	77.7	84.9	82.5
Martin Lake	2	88.0	77.3	73.3	82.5	86.7
Martin Lake	3	89.1	70.0	80.7	83.4	86.3
Sandow	4	100.3	82.6	92.9	74.3	97.5
Collin	1	7.4	5.6	14.3	22.1	13.4
DeCordova	1	19.7	41.5	46.6	54.4	56.3
Decordova CT's		1.9	2.4	3.6	6.5	4.2
Eagle Mountain	1	5.7	10.1	7.4	14.7	8.4
Eagle Mountain	2	5.2	12.6	12.9	16.7	18.9
Eagle Mountain	3	14.6	16.0	9.7	16.1	14.6
Graham	1	8.9	26.9	21.5	44.2	42.9
Graham	2	16.9	19.1	23.5	39.8	43.3
Lake Creek	1	0.2	3.9	8.5	27.2	20.6
Lake Creek	2	4.1	14.0	23.4	34.2	29.8
Lake Hubbard	1	11.6	12.0	13.4	23.2	19.5
Lake Hubbard	2	26.7	27.5	34.3	40.2	41.2
Morgan Creek	2	-	-	0.8	11.6	9.0
Morgan Creek	3	-	-	1.0	4.2	9.3
Morgan Creek	4	-	1.0	6.1	20.7	13.9
Morgan Creek	5	7.9	15.2	23.9	37.0	35.1
Morgan Creek	6	14.1	18.8	44.2	59.9	54.6
Morgan Creek CT's		0.9	1.0	1.6	4.1	2.9
North Lake	1	14.8	23.0	22.1	22.0	28.0
North Lake	2	10.9	20.2	24.7	30.0	23.1
North Lake	3	15.0	19.1	19.0	35.0	26.6
North Main	4	-	8.1	2.1	20.7	9.7
Parkdale	1	1.6	8.2	6.7	18.5	12.0
Parkdale	2	2.1	9.8	8.1	20.8	12.9
Parkdale	3	2.7	11.4	11.0	24.0	14.7
Permian Basin	5	4.0	9.5	22.0	31.8	26.6
Permian Basin	6	38.1	45.2	50.0	55.0	62.5
Permian Basin CT's		1.0	0.9	1.8	4.7	2.1
River Crest	6	-	-	0.9	18.9	12.5
Stryker Creek	1	4.7	3.7	20.4	29.3	24.3
Stryker Creek	2	23.3	24.2	32.4	43.8	48.8
Tradinghouse	1	11.2	30.0	30.7	36.4	44.0
Tradinghouse	2	21.6	22.0	49.8	50.0	52.1
Valley	1	9.2	12.5	21.4	32.3	26.3
Valley	2	6.8	25.7	34.6	43.2	48.9
Valley	3	2.8	5.8	10.7	17.8	12.7
Trinidad	6	6.9	10.4	19.8	18.8	22.8
Sweetwater	4	36.8	23.0	-	-	-
Sweetwater CT	1	18.2	23.8	-	-	-
Sweetwater CT	2	38.6	5.2	-	-	-
Sweetwater CT	3	43.9	37.1	-	-	-

## OPERATING STATISTICS – POWER

### Net Heat Rates (Btu/KWh) – Texas

Plant	Unit	Low	High
Comanche Peak	1	10,200	10,500
Comanche Peak	2	9,500	10,500
Big Brown	1	10,587	11,517
Big Brown	2	10,587	11,517
Monticello	1	10,587	11,517
Monticello	2	10,587	11,517
Monticello	3	10,587	11,517
Martin Lake	1	10,587	11,517
Martin Lake	2	10,587	11,517
Martin Lake	3	10,587	11,517
Sandow	4	10,587	11,517
Collin	1	10,430	32,426
DeCordova	1	9,812	13,316
Decordova CT's		9,250	9,800
Eagle Mountain	1	10,430	32,426
Eagle Mountain	2	10,430	32,426
Eagle Mountain	3	10,430	32,426
Graham	1	10,430	32,426
Graham	2	9,812	13,316
Lake Creek	1	10,430	32,426
Lake Creek	2	10,430	32,426
Lake Hubbard	1	10,430	32,426
Lake Hubbard	2	9,812	13,316
Morgan Creek	2	10,430	32,426
Morgan Creek	3	10,430	32,426
Morgan Creek	4	10,430	32,426
Morgan Creek	5	10,430	32,426
Morgan Creek	6	9,812	13,316
Morgan Creek CT's		9,250	9,800
North Lake	1	10,430	32,426
North Lake	2	10,430	32,426
North Lake	3	10,430	32,426
North Main	4	10,430	32,426
Parkdale	1	10,430	32,426
Parkdale	2	10,430	32,426
Parkdale	3	10,430	32,426
Permian Basin	5	10,430	32,426
Permian Basin	6	9,812	13,316
Permian Basin CT's		9,250	9,800
River Crest	6	10,430	32,426
Stryker Creek	1	10,430	32,426
Stryker Creek	2	9,812	13,316
Tradinghouse	1	9,812	13,316
Tradinghouse	2	9,812	13,316
Valley	1	10,430	32,426
Valley	2	9,812	13,316
Valley	3	10,430	32,426
Trinidad	6	10,430	32,426
Sweetwater	4	11,500	12,000
Sweetwater CT	1	11,500	12,000
Sweetwater CT	2	11,500	12,000
Sweetwater CT	3	11,500	12,000

## OPERATING STATISTICS – POWER

### Fuel Mix and Average Cost – Texas

	2003	2002	2001	2000	1999
<b>Generation (MWh)</b>					
Nuclear	17,749,343	16,579,084	18,322,265	18,487,842	17,357,539
Lignite/Coal	43,240,756	39,817,056	39,506,193	40,993,945	40,844,661
Gas/Oil	13,098,982	18,733,486	24,371,090	32,102,173	31,741,679
Gas/Oil Divested	–	854,232	3,626,265	5,292,578	4,629,957
<b>Total</b>	<b>74,089,081</b>	<b>75,983,858</b>	<b>85,825,813</b>	<b>96,876,538</b>	<b>94,573,836</b>
<b>Generation Mix (%)</b>					
Nuclear	24%	22%	21%	19%	18%
Lignite/Coal	58%	52%	46%	42%	43%
Gas/Oil	18%	26%	33%	39%	39%
<b>Total</b>	<b>100%</b>	<b>100%</b>	<b>100%</b>	<b>100%</b>	<b>100%</b>
<b>Fuel Cost (\$000)</b>					
Nuclear	79,503	76,365	88,796	99,151	103,363
Lignite / Coal	517,470	482,811	543,498	464,558	418,423
Gas/ Oil	896,304	786,109	1,285,658	1,761,258	1,007,042
<b>Total</b>	<b>1,493,277</b>	<b>1,345,285</b>	<b>1,917,952</b>	<b>2,324,967</b>	<b>1,528,828</b>
<b>Average Fuel Cost (\$/MWh)</b>					
Nuclear	4.48	4.61	4.85	5.36	5.95
Lignite / Coal	11.97	12.13	13.76	11.33	10.24
Gas/ Oil	68.43	40.13	45.92	47.10	27.69
<b>Total</b>	<b>20.16</b>	<b>17.70</b>	<b>22.35</b>	<b>24.00</b>	<b>16.17</b>

## OPERATING STATISTICS – POWER

### O&M / SG&A

(\$000's)	2003	2002	2001	2000	1999
Nuclear	213,725	236,305	194,300	208,571	217,790
Lignite/Coal	218,272	195,458	163,925	146,978	165,715
Gas/Oil	111,283	105,904	120,016	125,123	129,717
Other	50,809	71,194	133,359	103,223	117,768
<b>Total</b>	<b>594,089</b>	<b>608,861</b>	<b>611,600</b>	<b>583,895</b>	<b>630,990</b>

### Depreciation Rates

(%)	Apr-Dec 2003 <sup>(1)</sup>	March 2003	2002	2001	2000	1999
Nuclear	1.83	2.51	2.51	2.51	2.51	2.51
Lignite/Coal	2.97	2.46	2.46	2.46	2.46	2.46
Gas/Oil	2.31	2.00	2.00	2.00	2.00	2.00

### Net Heat Rate

(Btu/KWh)	2003	2002	2001	2000	1999
Nuclear	10,399	10,470	9,983	10,401	9,952
Lignite/Coal	11,220	11,192	11,216	11,119	11,006
Gas/Oil	11,201	10,998	10,698	10,715	10,473

### Outage Management (Baseload)

(TWh)	2003	2002	2001	2000	1999
<b>Total</b>					
Planned	3.3	5.1	3.1	3.3	4.1
Unplanned	5.6	6.6	6.8	4.6	3.5
<b>Total</b>	<b>8.9</b>	<b>11.7</b>	<b>9.9</b>	<b>7.9</b>	<b>7.6</b>
<b>Nuclear</b>					
Planned	0.7	2.2	0.8	1.0	1.9
Unplanned	1.1	0.6	0.4	0.0	0.1
<b>Total</b>	<b>1.8</b>	<b>2.8</b>	<b>1.2</b>	<b>1.0</b>	<b>2.0</b>
<b>Lignite/Coal</b>					
Planned	2.6	2.9	2.3	2.3	2.2
Unplanned	4.5	6.0	6.4	4.6	3.4
<b>Total</b>	<b>7.1</b>	<b>8.9</b>	<b>8.7</b>	<b>6.9</b>	<b>5.6</b>

<sup>(1)</sup> Plant specific depreciation rates included: Tradinghouse 2.35%, DeCordova 2.22%, and Big Brown 5.17%.

## OPERATING STATISTICS – TRADING

Trading refers to risk management and value creation activities undertaken to balance customer demand for energy with the supply of energy in an economically efficient and effective manner. Retail and wholesale demand is generally greater than volumes that can be supplied by TXU Energy's base load production. Trading acts to provide additional supply balancing through TXU Energy's gas/oil-fired generation or purchases of power. This operation manages the commodity volume and price risks inherent in TXU Energy's generation and sales operations through supply structuring, pricing and risk management activities. Risk management activities include hedging both future power sales and purchases of fuel supplies for the generation plants. This operation is also responsible for the efficient dispatch of power from its generation plants.

### Commodity Market Prices

		NYMEX (GDD) <sup>(1)</sup>	Power Prices (MWD) <sup>(2)</sup>			Heat Rates		
			5 X 16	5 X 8	7 X 24	5 X 16	5 X 8	7 X 24
<b>2003</b>	Q1	\$ 5.878	\$ 52.796	\$ 37.348	\$ 45.781	8.982	6.354	7.789
	Q2	\$ 5.738	\$ 51.098	\$ 31.964	\$ 44.224	8.905	5.571	7.707
	Q3	\$ 4.897	\$ 42.873	\$ 28.794	\$ 36.913	8.755	5.880	7.538
	Q4	\$ 5.498	\$ 38.535	\$ 24.695	\$ 34.368	7.009	4.491	6.251
	<b>Total 2003</b>	<b>\$ 5.503</b>	<b>\$ 46.326</b>	<b>\$ 30.700</b>	<b>\$ 40.322</b>	<b>8.413</b>	<b>5.574</b>	<b>7.321</b>
<b>2002</b>	Q1	\$ 2.491	\$ 21.448	\$ 14.158	\$ 18.880	8.611	5.684	7.580
	Q2	\$ 3.405	\$ 29.885	\$ 15.145	\$ 24.499	8.777	4.448	7.195
	Q3	\$ 3.192	\$ 30.072	\$ 18.031	\$ 25.803	9.422	5.650	8.085
	Q4	\$ 4.325	\$ 34.796	\$ 22.449	\$ 30.308	8.046	5.191	7.008
	<b>Total 2002</b>	<b>\$ 3.353</b>	<b>\$ 29.050</b>	<b>\$ 17.446</b>	<b>\$ 24.872</b>	<b>8.714</b>	<b>5.243</b>	<b>7.467</b>

(1) NYMEX gas price is the Gas Daily data for day ahead prices in the cash month in \$/MMBtu.

(2) Power Prices are the Megawatt Daily non zonal ERCOT day ahead cash price in \$/MWh.

## OPERATING STATISTICS – TRADING

### Selected Credit Statistics for Wholesale Sales

<b>(\$ millions except percentages)</b>	<b>2003</b>	<b>2002</b>
Gross Credit Exposure (Net of Collateral)	\$ 740	\$ 866
Investment Grade Credit Exposure (Net of Collateral)		
Less than 2 years	\$ 424	\$ 624
2 - 5 years	119	22
Greater than 5 years	119	4
<b>Total</b>	<b>\$ 662</b>	<b>\$ 650</b>
Non Investment Grade Credit Exposure (Net of Collateral)		
Less than 2 years	\$ 50	\$ 195
2 - 5 years	14	21
Greater than 5 years	14	0.3
<b>Total</b>	<b>\$ 78</b>	<b>\$ 216</b>
% Investment Grade (Net of Collateral)	89%	75%
% Non Investment Grade (Net of Collateral)	11%	25%
<b>Total</b>	<b>100%</b>	<b>100%</b>
Credit Exposure Maturities (Net of Collateral)		
Less than 2 years	64%	94%
2 - 5 years	18%	5%
Greater than 5 years	18%	1%
<b>Total</b>	<b>100%</b>	<b>100%</b>

### Selected Credit Statistics for Retail Sales

<b>(\$ millions except percentages)</b>	<b>2003</b>	<b>2002</b>
Gross Credit Exposure (Net of Collateral)	\$ 226	\$ 319
Investment Grade (LBM) Credit Exposure (Net of Collateral)		
Less than 2 years	\$ 155	\$ 139
2 - 5 years	10	28
Greater than 5 years	0	0
<b>Total</b>	<b>\$ 165</b>	<b>\$ 167</b>
Non Investment Grade (LBM) Exposure (Net of Collateral)		
Less than 2 years	\$ 57	\$ 152
2 - 5 years	4	0
Greater than 5 years	0	0
<b>Total</b>	<b>\$ 61</b>	<b>\$ 152</b>
% Investment Grade	73%	52%
% Non Investment	27%	48%
<b>Total</b>	<b>100%</b>	<b>100%</b>
Credit Exposure Maturities (LBM) (Net of Collateral)		
Less than 2 years	94%	91%
2 - 5 years	6%	9%
Greater than 5 years	0%	0%
<b>Total</b>	<b>100%</b>	<b>100%</b>

Note: The tables shown above present the distribution of credit exposure for trade accounts receivable from large business customers, commodity contract assets and other derivative assets that arise primarily from hedging activities.

## OPERATING STATISTICS – MARKETING

### Metrics

	2003	2002
<b>Electric Operating Revenues (\$ millions)</b>		
Residential	\$ 3,311	\$ 3,107
Small Business	\$ 1,238	\$ 1,305
Large Business	\$ 1,935	\$ 2,110
<b>Electric Energy Sales (GWh)</b>		
Residential	35,981	37,692
Small Business	12,986	15,907
Large Business	30,955	36,982
<b>Number of Electric Customers (thousands)</b>		
<b>Native Market:</b>		
Residential	2,059	2,204
Small Business	<u>317</u>	<u>328</u>
Total Native Market	2,376	2,532
<b>Other Markets:</b>		
Residential	148	98
Small Business	<u>4</u>	<u>5</u>
Total Other Markets	<u>152</u>	<u>103</u>
Large Business	<u>69</u>	<u>78</u>
<b>Total Electric Customers</b>	<b>2,597</b>	<b>2,713</b>
<b>Net Customer Change</b>		
Native Market	( 6.2%)	( 3.5%)
Other Markets	47.6%	1,473%
<b>Call Center Metrics</b>		
Answer Speed (seconds)	268	93
Abandoned Calls	26%	11%
<b>Credit and Collection Metrics</b>		
Average Receivables (\$ millions)		
Less than 30 days	302.7	341.7
30-60 days	55.9	88.3
60-90 days	19.5	55.2
Greater than 90 days	24.7	78.4
Bad Debt Expense	\$ 120.5	\$ 118.4
Bad Debt as % of Total Revenues	1.84%	1.80%
<b>Total Retail SG&amp;A</b>	<b>\$ 299.7</b>	<b>\$ 391.5</b>

## OPERATING STATISTICS – MARKETING

### Price to Beat and Gas Component Information – Residential

Affiliate REP	Docket No.	Effective	Gas Price As Filed	Gas Price Increase	Months	Fuel Factor	Average Price <sup>(1)</sup> (¢/KWh)
TXU	24040	01/01/2002	\$ 3.111	–	–	–	8.26
	25802	08/27/2002	\$ 3.619	16.3%	All	2.8935	8.66
	27281	03/11/2003	\$ 4.910	35.7%	All	3.9265	9.69
	28191	08/22/2003	\$ 5.362	9.2%	All	4.2877	10.06
	29516	05/13/2004	\$ 5.785	7.9%	All	4.6264	10.39
First Choice	24194	01/01/2002	\$ 3.111	–	–	–	8.66
	25885	08/27/2002	\$ 3.817	22.7%	All	2.67396	9.15
	27167	02/04/2002	\$ 4.526	18.6%	All	3.17085	9.65
	27390	03/27/2003	\$ 5.166	14.1%	All	3.61921	10.10
	27511	04/22/2003	\$ 5.958	15.3%	All	4.17403	10.65
Mutual Energy - CPL	24195	01/01/2002	\$ 3.111	–	–	–	8.88
	25873	08/27/2002	\$ 3.795	22.0%	Mar-Jun	4.2908	9.52
					Jul-Oct	3.9793	
					Nov-Feb	3.3763	
	27376	03/25/2003	\$ 5.123	35.0%	Mar-Jun	5.7926	10.93
				Jul-Oct	5.3721		
				Nov-Feb	4.5580		
Mutual Energy - WTU	24335	01/01/2002	\$ 3.111	–	–	–	8.90
	25874	08/27/2002	\$ 3.795	22.0%	Dec-Feb	3.9894	9.71
					Mar-May	6.0140	
					Jun-Aug	4.9507	
					Sep-Nov	3.8627	
27377	03/25/2003	\$ 5.123	35.0%	Dec-Feb	5.3857	11.34	
				Mar-May	8.1189		
				Jun-Aug	6.6834		
				Sep-Nov	5.2146		
Reliant	23950	01/01/2002	\$ 3.111	–	–	–	8.62
	25840	08/27/2002	\$ 3.729	19.9%	All	3.0377	9.12
	26933	12/20/2002	\$ 4.017	7.7%	All	3.2716	9.35
	27320	03/11/2003	\$ 4.956	23.4%	All	4.0372	10.12
	27956	07/26/2003	\$ 6.100	23.1%	All	4.9698	11.05

### Native Market Price Comparison

	Rates (¢ / kwh) <sup>(1)</sup>		
	12/31/03	06/03/03	12/31/02
TXU – PTB	10.06	9.69	8.66
Reliant	9.05	8.73	8.23
Direct Energy	9.60	9.28	8.48
First Choice (TNMP)	10.75	10.75	8.20
Entergy Solutions	8.80	8.60	8.15
Green Mountain	10.66	10.30	9.00

<sup>(1)</sup> Rates calculated for residential customer using 12,000 kwh/year.

**OPERATING STATISTICS – MARKETING**  
**Rate Tariffs – PTB (Effective 5/13/04)**

<b>Residential - R</b>			
Facilities	\$	5.34 per Month	
Energy		<u>June - October</u>	<u>November - May</u>
	\$	0.0557 per kWh	\$ 0.0524 per kWh for the first 600 kWh \$ 0.0366 per kWh for each additional kWh
Fuel	\$	0.046264 per kWh	
Power Cost Recovery Factor		\$0.0004183 per kWh	

<b>Residential - RSE</b>			
Facilities	\$	4.54 per Month	
Energy		<u>June - October</u>	<u>November - May</u>
	\$	0.0474 per kWh	\$ 0.0446 per kWh for the first 600 kWh \$ 0.0312 per kWh for each additional kWh
Fuel	\$	0.046264 per kWh	
Power Cost Recovery Factor		\$0.0004183 per kWh	

<b>Residential - RLU</b>			
Facilities	\$	- per Month	
Energy		<u>June - October</u>	<u>November - May</u>
	\$	0.0557 per kWh	\$ 0.0524 per kWh
Fuel	\$	0.046264 per kWh	
Power Cost Recovery Factor		\$0.0004183 per kWh	

<b>Residential - RTU</b>			
Facilities	\$	8.00 per Month	
Energy		<u>On-peak *</u>	<u>Off-peak *</u>
	\$	0.1377 per kWh	\$ 0.0366 per kWh
* On-peak hours are the 8 hours between 12 noon and 8 pm each weekday (Monday-Friday) except July 4 and Labor Day during the calendar months of June through September. All remaining hours are off-peak.			
Fuel	\$	0.046264 per kWh	
Power Cost Recovery Factor		\$0.0004183 per kWh	

<b>Residential - RTU1</b>				
Facilities	\$	8.00 per Month		
Energy *		<u>period 4</u>	<u>period 3</u>	<u>period 2</u>
	per kWh	\$ 0.1193	0.055	0.0311
Demand	\$	1.71 per kW		
		\$0.94 per kW in excess of Contract kW		
Fuel	\$	0.046264 per kWh		
Power Cost Recovery Factor		\$0.0004183 per kWh		
* For pricing period definitions see the tariff.				

# OPERATING STATISTICS – MARKETING

## Rate Tariffs - PTB

General Service Secondary - GS		
Facilities	\$	12.90 per Month
Demand	\$	7.78 per kW in excess of 10 kW \$0.94 per kW in excess of Contract kW
Energy (W/O DM)	\$	0.0572 per kWh for the first 2500 kWh 0.0295 per kWh for all additional kWh
Energy (With DM)	\$	0.0572 per kWh for the first 2500 kWh 0.0295 per kWh for the next 3500kWh + 170 kWh per kW >10 kW 0.0066 per kWh for all additional kWh
Fuel	Jun-Sep	Oct-May
	\$	0.050764 0.043326 per kWh
PCRF	\$	0.00037224

**Demand Determination**

(a) Demand is the smaller of :

- 1) current month kW;
- 2) on-peak kW plus 25% of the current month kW in excess of the on-peak kW

But is not less than the highest of:

(b) 1) 80% of on-peak kW;  
2) 50% of contract kW;  
3) 50% of annual kW

For Time of Day option rates see tariff.

General Service Secondary State Institutions of Higher Education - GSSE		
Facilities	\$	10.98 per Month
Demand	\$	6.62 per kW in excess of 10 kW \$0.94 per kW in excess of Contract kW
Energy (W/O DM)	\$	0.0487 per kWh for the first 2500 kWh 0.0251 per kWh for all additional kWh
Energy (With DM)	\$	0.0487 per kWh for the first 2500 kWh 0.0251 per kWh for the next 3500kWh + 170 kWh per kW >10 kW 0.0056 per kWh for all additional kWh
Fuel	Jun-Sep	Oct-May
	\$	0.050764 0.043326 per kWh
PCRF	\$	0.00037224

**Demand Determination**

(a) Demand is the smaller of :

- 1) current month kW;
- 2) on-peak kW plus 25% of the current month kW in excess of the on-peak kW

But is not less than the highest of:

(b) 1) 80% of on-peak kW;  
2) 50% of contract kW;  
3) 50% of annual kW

General Service Primary - GP		
Facilities	\$	13.96 per Month
Demand	\$	7.10 per kW in excess of 10 kW \$0.94 per kW in excess of Contract kW
Energy (W/O DM)	\$	0.0578 per kWh for the first 2500 kWh 0.0298 per kWh for all additional kWh
Energy (With DM)	\$	0.0578 per kWh for the first 2500 kWh 0.0298 per kWh for the next 3500kWh + 215 kWh per kW >10 kW 0.0055 per kWh for all additional kWh
Fuel	Jun-Sep	Oct-May
	\$	0.049979 \$ 0.042543 per kWh
PCRF	\$	0.0003572

**Demand Determination**

(a) Demand is the smaller of :

- 1) current month kW;
- 2) on-peak kW plus 25% of the current month kW in excess of the on-peak kW

But is not less than the highest of:

(b) 1) 80% of on-peak kW;  
2) 50% of contract kW;  
3) 50% of annual kW

For Time of Day option rates see tariff.

General Service Primary State Institutions of Higher Education - GPSE		
Facilities	\$	11.88 per Month
Demand	\$	6.04 per kW in excess of 10 kW \$0.94 per kW in excess of Contract kW
Energy (W/O DM)	\$	0.0492 per kWh for the first 2500 kWh 0.0253 per kWh for all additional kWh
Energy (With DM)	\$	0.0492 per kWh for the first 2500 kWh 0.0253 per kWh for the next 3500kWh + 215 kWh per kW >10 kW 0.0047 per kWh for all additional kWh
Fuel	Jun-Sep	Oct-May
	\$	0.049979 \$ 0.042543 per kWh
PCRF	\$	0.0003572

**Demand Determination**

(a) Demand is the smaller of :

- 1) current month kW;
- 2) on-peak kW plus 25% of the current month kW in excess of the on-peak kW

But is not less than the highest of:

(b) 1) 80% of on-peak kW;  
2) 50% of contract kW;  
3) 50% of annual kW

# OPERATING STATISTICS – MARKETING

## Rate Tariffs - PTB

High Voltage - HV		
Facilities	\$ 386.20	per Month
Demand	\$ 11.31	per kW
	\$0.94	per kW in excess of Contract kW
Energy	\$ 0.005	per kWh
Fuel	Jun-Sep	Oct-May
	\$ 0.049410	0.041971 per kWh
PCRF	\$ 0.0002905	

**Demand Determination**

(a) Demand is the smaller of :

- 1) current month kW;
- 2) on-peak kW plus 25% of the current month kW in excess of the on-peak kW

(b) But is not less than the highest of:

- 1) 80% of on-peak kW;
- 2) 50% of contract kW;
- 3) 50% of annual kW

For Time of Day option rates see tariff.

High Voltage State Institutions of Higher Education - HVSE		
Facilities	\$ 328.68	per Month
Demand	\$ 9.62	per kW
	\$0.94	per kW in excess of Contract kW
Energy	\$ 0.0043	per kWh
Fuel	Jun-Sep	Oct-May
	\$ 0.049410	0.041971 per kWh
PCRF	\$ 0.0002905	

**Demand Determination**

(a) Demand is the smaller of :

- 1) current month kW;
- 2) on-peak kW plus 25% of the current month kW in excess of the on-peak kW

(b) But is not less than the highest of:

- 1) 80% of on-peak kW;
- 2) 50% of contract kW;
- 3) 50% of annual kW

For Time of Day option rates see tariff.

Municipal Service - MS		
Facility	13.96	per month
Energy	<u>Jun - Oct</u>	<u>Nov - May</u>
	\$0.0655	\$0.0504 per kWh
Fuel	\$ 0.046264	per kWh
PCRF	\$ 0.0006307	per kWh

Municipal Pumping Secondary - MP SEC		
Facilities	\$ 13.02	per Month
Demand	\$ 7.86	per kW in excess of 10 kW
	\$0.94	per kW in excess of Contract kW
Energy (W/O DM)	\$ 0.0578	per kWh for the first 2500 kWh
	\$ 0.0298	per kWh for all additional kWh
Energy (With DM)	\$ 0.0578	per kWh for the first 2500 kWh
	\$ 0.0298	per kWh for the next 3500kWh + 170 kWh per kW >10 kW
	\$ 0.0067	per kWh for all additional kWh
Fuel	\$ 0.046264	per kWh
PCRF	\$0.00037224	

**Demand Determination**

(a) Demand is the smaller of :

- 1) current month kW;
- 2) on-peak kW plus 25% of the current month kW in excess of the on-peak kW

(b) But is not less than the highest of:

- 1) 80% of on-peak kW;
- 2) 50% of contract kW;
- 3) 50% of annual kW

For Time of Day option rates see tariff.

Municipal Pumping Primary - MP PRI		
Facilities	\$ 13.96	per Month
Demand	\$ 7.10	per kW in excess of 10 kW
	\$0.94	per kW in excess of Contract kW
Energy (W/O DM)	\$ 0.0578	per kWh for the first 2500 kWh
	\$ 0.0298	per kWh for all additional kWh
Energy (With DM)	\$ 0.0578	per kWh for the first 2500 kWh
	\$ 0.0298	per kWh for the next 3500kWh + 215 kWh per kW >10 kW
	\$ 0.0055	per kWh for all additional kWh
Fuel	\$ 0.045163	per kWh
PCRF	\$ 0.0003572	

**Demand Determination**

(a) Demand is the smaller of :

- 1) current month kW;
- 2) on-peak kW plus 25% of the current month kW in excess of the on-peak kW

(b) But is not less than the highest of:

- 1) 80% of on-peak kW;
- 2) 50% of contract kW;
- 3) 50% of annual kW

For Time of Day option rates see tariff.

# OPERATING STATISTICS – MARKETING

## Rate Tariffs – PTB

### Street Lighting - SL

Facilities \$ 23.27 per governmental entity

For definitions of schedules see tariff.

Luminaire Charge, per Luminaire									
Lamp	Watts	Lumens	kWh	Schedule				Rect- angular	Post-Top
				A	B	C	D		
Mercury Vapor	175	7,900	70	\$7.82	\$15.35	\$3.63	\$2.47	\$19.03	\$12.10
	400	21,000	150	\$11.49	\$18.66	\$6.79	\$5.26	N.A.	N.A.
	1,000	63,000	370	\$25.50	\$33.59	\$18.05	\$12.94	N.A.	N.A.
Sodium Vapor	100	9,500	40	\$7.03	\$14.56	\$2.79	\$1.40	\$19.17	\$11.49
	150	16,000	70	\$8.84	\$15.96	\$4.33	\$2.47	\$23.87	N.A.
	200	22,000	80	\$9.63	\$16.70	\$4.75	\$2.79	\$24.24	N.A.
	250	27,500	100	\$10.14	\$17.22	\$5.44	\$3.49	\$24.71	N.A.
	400	50,000	160	\$14.42	\$23.78	\$8.61	\$5.58	\$36.06	N.A.
	1,000	140,000	375	\$27.96	\$37.36	\$19.59	\$13.07	\$48.81	N.A.
Metal Halide	175	14,000	65	\$9.45	\$17.03	\$5.12	\$2.28	\$21.26	\$16.89
	250	25,000	100	\$12.03	\$20.57	\$6.96	\$3.77	\$30.91	N.A.
	400	36,000	160	\$14.61	\$24.06	\$8.79	\$5.26	\$40.53	N.A.
	1,000	110,000	370	\$26.75	\$36.15	\$19.26	\$12.75	\$49.55	N.A.
Other									
Incandescent*		All		\$7.03					
Wallpack Mercury Vapor*		250W		\$16.38					
Fluorescent*		\$20.01							
Historical		\$19.82							
*Closed to new street lighting installations									

Fuel \$ 0.046264 per kWh

PCRF \$ 0.00037224

### Outdoor Lighting - OL

#### Monthly Rate

##### Guard Lights

Type	Watts	kWh	Lumens	Amount
Mercury Vapor	175	70	7,900	\$ 7.91
	400	150	21,000	\$12.00
Sodium Vapor	100	40	9,500	\$ 7.44
	200	80	22,000	\$10.42

##### Flood Lights

Type	Watts	KWh	Lumens	Amount
Metal Halide	250	100	25,000	\$13.77
	400	160	36,000	\$16.66
Sodium Vapor	100	40	9,500	\$10.05
	250	100	27,000	\$12.84
	400	160	50,000	\$16.43

Fuel Jun-Sep Oct-May  
\$ 0.050764 \$ 0.043326 per kWh

PCRF \$ 0.00037224

## OPERATING STATISTICS – TXU ENERGY

	2003	2002	2001(a)(b)
<b>Operating Statistics – Volumes</b>			
Retail Electricity (GWh)			
Residential	35,981	37,692	
Small Business(c)	12,986	15,907	
Large Business and Other	30,955	36,982	
Total Retail Electricity	<u>79,922</u>	<u>90,581</u>	<u>99,151</u>
Wholesale Electricity (GWh)	<u>37,362</u>	<u>29,649</u>	<u>6,409</u>
Production and Purchased Power (GWh)			
Nuclear and Lignite/Coal (Base Load)	59,028	54,738	57,828
Gas/Oil and Purchased Power	63,319	70,321	52,925
Total Production and Purchased Power	<u>122,347</u>	<u>125,059</u>	<u>110,753</u>
<b>Customer Counts</b>			
Retail Electricity Customers (end of period and in thousands – based on number of meters)			
Residential	2,207	2,302	
Small Business	321	333	
Large Business and Other	69	78	
Total Retail Electricity Customers	<u>2,597</u>	<u>2,713</u>	<u>2,728</u>
<b>Operating Revenues (\$ millions):</b>			
Retail Electricity Revenues			
Residential	\$ 3,311	\$ 3,108	\$ 3,255
Business and Other	<u>3,173</u>	<u>3,415</u>	3,837
Total Retail Electricity Revenues	6,484	6,523	7,902
Wholesale Electricity Revenues	1,274	857	96
Hedging and Risk Management Activities	18	142	358
Other Revenues	219	169	(142)
Total Operating Revenues	<u>\$ 7,995</u>	<u>\$ 7,691</u>	<u>\$ 7,404</u>
<b>Weather (Average for Service Territory)</b>			
Percent of Normal			
Cooling Degree Days	103.1%	99.8%	100.5%
Heating Degree Days	94.0%	102.0%	97.5%

- (a) Data for 2001 is included above for the purpose of providing historical information about the Energy segment after giving effect to the unbundling of the integrated electric utility as a result of the transition to competition.
- (b) Retail volume and customer count data for 2001 not available by class.
- (c) Customers with demand of less than 1MW annually.

# ERCOT/TEXAS MARKET/REGULATORY HIGHLIGHTS

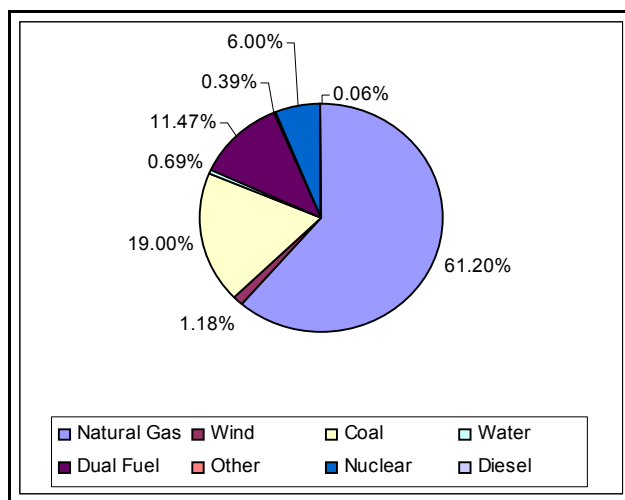
## Electric Reliability Council of Texas (ERCOT)

The Electric Reliability Council of Texas is the Independent System Operator and the regional reliability coordinator of the various electricity systems in Texas. ERCOT is one of ten regional reliability councils in North America. As one of the largest control areas in the United States, the organization serves seven million customers and oversees the operation of over 78,000 megawatts of generation and 37,500 miles of transmission lines in Texas. ERCOT serves approximately 85 percent of the state's electric load and 75 percent of the geographic land area in Texas.

	<u>2003</u>
Market Peak Demand – Summer (MWs) .....	60,157
Total Installed Capacity (MWs) .....	76,916
Interconnection Capacity (MWs) .....	800
Reserve Margin .....	30%
Number of Competitive Customers (millions) .....	5.58

	<u>North Texas</u>	<u>South Texas</u>
Usage Per Residential Customer (KWh) .....	1,302	1,277

**ERCOT Summer 2003 Fuel Types**



## ERCOT/TEXAS MARKET/REGULATORY HIGHLIGHTS

### Transmission Congestion Management in ERCOT

Transmission congestion is the additional cost associated with operating generation in a less than perfect economic manner due to the reality of a less than perfect transmission system. There are two sides to congestion costs: the cost of additional transmission versus the cost of less-than-optimal generation dispatch. The desired result is to minimize combined cost.

When the Texas competitive retail electricity market opened in 2002, the method of dealing with transmission congestion was referred to as “zonal”. ERCOT is divided into zones for transmission purposes, and currently uses “zonal” congestion management. Zonal congestion involves competitive solutions between different regions within the state. A competitive solution exists when multiple owners of generation can compete to resolve the congestion problem by making offers to increase or decrease their generation output. Costs for relieving congestion between transmission zones are charged directly to the companies scheduling the power transfer.

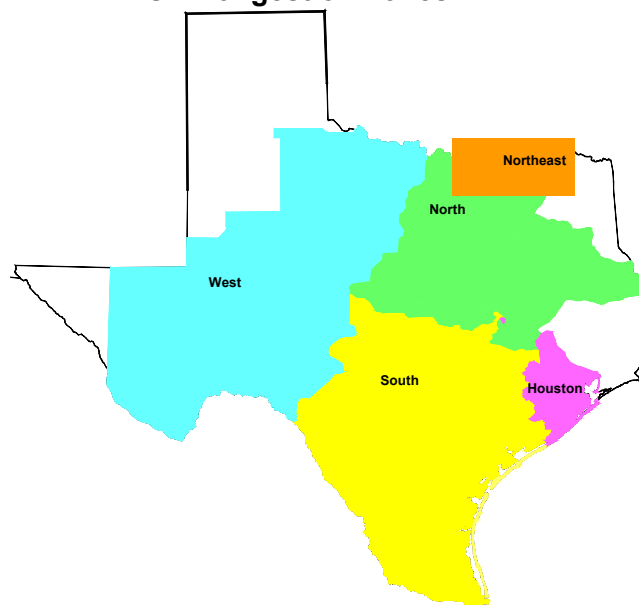
Local congestion occurs within the zones. Typically there are not enough generation owners in the area to compete to resolve the congestion. Costs to resolve local congestion within zones are shared by all companies on a proportional basis. The congestion costs shared by all consumers within zones totaled \$223 million in 2003.

The challenge for ERCOT is to balance this cost against the cost of additional transmission investment to relieve this congestion. Transmission companies are actively addressing local congestion in a cost-effective manner by adding new transmission facilities in those locations identified by high local congestion costs.

The Texas market is now considering adoption of a “nodal market design” for transmission congestion management. This method differs from the zonal model primarily in the level of granularity used in dealing with generators. The nodal market makes no distinction between zonal and local congestion. Market participants, in cooperation with ERCOT and the Public Utility Commission of Texas, are currently pursuing a cost-effective design for a Texas Nodal Market.

A cost benefit study is currently underway to evaluate this design against the current zonal market design, and will be complete in November 2004. Transition to a nodal system is planned for 2006. Changes to business practices could occur in 2005 as a nodal transition program is developed and implemented.

### ERCOT Congestion Zones



# ERCOT/TEXAS MARKET/REGULATORY HIGHLIGHTS

## Market Rules Overview

	Definition	Impact to TXU
<b>Price to Beat</b>	<p>TXU Energy may not charge rates to those customers that are different from the price to beat rates until the earlier of:</p> <ul style="list-style-type: none"> <li>(a) January 1, 2005 or</li> <li>(b) Until 40% of the electric power consumed by customers in those respective customer classes is supplied by competing REPs</li> </ul> <p>Thereafter, TXU Energy may offer rates different from the price-to-beat to customers in that class, but must also continue to make the price-to-beat rate available for residential and small business customers until January 1, 2007.</p>	<p>In December 2003, TXU Energy met the 40% requirement to be allowed to offer alternatives to the price-to-beat rate for <b>small business customers</b> in the native market.</p>
<b>PTB Fuel Factor Adjustment</b>	<p>Twice per year, affiliated REPs may request that the PUC adjust the fuel factor component of the price-to-beat rate based on changes in the market price of natural gas. Under amended rules, a request for a change in the fuel factor can be petitioned if natural gas futures move more than 5% (10% if the petition is filed after November 15 of any year) from the level used to set the existing price-to-beat fuel factor rate.</p>	<p>In January and July of 2003, TXU Energy exercised its right to increase the fuel factor components of its price-to-beat rates.</p>
<b>Unregulated Pricing on ERCOT Wholesale Power Transactions</b>	<p>Power generation companies affiliated with electric delivery utilities may charge unregulated prices in connection with ERCOT wholesale power transactions.</p>	
<b>Provider of Last Resort (POLR)</b>	<p>Under the POLR framework, the POLR provides electric service only to customers who request POLR service, whose selected REP goes out of business, or who are transferred to the POLR by other REPs for reasons other than non-payment.</p>	<p>TXU Energy did not bid to be the POLR, but was designated POLR through lottery for residential and small business customers in certain West Texas service areas and for small business customers in the Houston service area.</p>

## ERCOT/TEXAS MARKET/REGULATORY HIGHLIGHTS

### Summary of Settlement Plan

Major Element	Description
<b>Excess Mitigation Credit</b>	Over the two year period ended December 21, 2003, TXU's energy delivery business implemented a stranded cost excess mitigation credit in the amount of \$389 million, plus \$26 million in interest, applied as a reduction to delivery rates charged to all REPs, including TXU Energy.
<b>Regulatory Asset Securitization</b>	US Holdings received a financing order authorizing the issuance of securitization bonds up to \$1.3 billion to recover regulatory asset stranded costs and other qualified costs. TXU's energy delivery business, through its bankruptcy remote financing subsidiary, issued an initial \$500 million of securitization bonds in August 2003 and anticipates issuance of an additional \$790 million in 2004. The principal and interest on the bonds is recoverable through a delivery fee surcharge to all REPs, including TXU Energy.
<b>Retail Clawback Credit</b>	A retail clawback credit related to residential customers was implemented in January 2004. The amount of the credit is equal to the number of residential customers retained by TXU Energy in the native market on January 1, 2004, less the number of new residential customers TXU Energy has added outside of the native market as of January 1, 2004 multiplied by \$90. The estimated credit of \$173 million will be applied to residential delivery rates charged by TXU's energy delivery business to all REPS, including TXU Energy.
<b>Stranded Costs and Fuel Cost Recovery</b>	TXU Energy's stranded costs, not including regulatory assets, are fixed at zero. The Company will not seek to recover its unrecovered fuel costs which existed at December 31, 2001 nor pursue a final fuel cost reconciliation.

For detailed information related to various regulatory proceedings in which TXU is or has recently been involved, please see our Annual Reports filed with the SEC on Form 10-K or our most recent Quarterly Reports filed with the SEC on Form 10-Q.

## ERCOT/TEXAS MARKET/REGULATORY HIGHLIGHTS

### Public Utility Commission of Texas

1701 N. Congress Avenue  
 P.O. Box 13326  
 Austin, Texas 78711-3326  
 (512) 936-7000

The PUC of Texas is responsible for:

- Ensuring that Texans have access to high-quality competitive alternatives for electric service
- Providing exemplary customer service in disseminating educational information, assisting customers to resolve disputes concerning electric service and ensuring compliance with relevant law and regulations
- Implementing the Public Utility Regulatory Act in a way that observes the letter and captures the spirit of the legislative directives
- Resolving contested matters efficiently, emphasizing collaboration and consensus

The Commission consists of three members appointed by the Governor and confirmed by the state senate for six-year staggered terms of office. A chairperson is designated by the Governor.

Commissioner	Term Expires	Background
<b>Paul Hudson (Chair)</b>	September 2009	Previously, Director of Policy for the Office of the Governor; a bachelor's degree from University of Texas and a master's degree from Arizona State University
<b>Julie Parsley</b>	September 2005	Previously, Solicitor General of Texas in the Office of the Attorney General; a graduate of Texas A&M with law degree from Texas Tech University School of Law.
<b>Barry T. Smitherman</b>	September 2007	Previously, served as Harris County Assistant District Attorney; a graduate of Texas A&M with law degree from University of Texas School of Law and master's degree from Harvard University.

**SCHEDULE OF LONG-TERM DEBT**  
**As of December 31, 2003**  
(\$ millions)

Issue	Year Due	Fixed/ Floating	2004	2005	2006	2007	2008 & Beyond	Total	Redemption Price at 12/31/03	Date of Next Redemption Price	Next Redemption Price
<b>TXU Corp</b>											
<i>Senior Notes</i>											
Series B, 6.375%	2004	Fixed	175					175		10/01/04 (c)	T+5
Series C, 4.050%	2008	Fixed					200	200		01/01/08	100.00
Series E, 6.375%	2004	Fixed	2					2		(h)	T+20
Series J, 6.375%	2006	Fixed			800			800		06/15/06 (e)	
Series K, 4.75%	2006	Fixed			500			500			
Series L, 5.45%	2007	Fixed				500		500			
Series M, 5.80%	2008	Fixed					440	440			
Conv Senior Notes, 2.65%	2033	Floating					525	525		07/15/08	100.00
<i>Other</i>											
Fixed Overfund Trust Debt	2004	Fixed	91					91		(e)	
Building Financing, 8.820%	2022	Fixed	10	9	9	9	93	130			
Unamortized Prem and Disc							30	30			
<b>Total TXU Corp</b>			<b>278</b>	<b>9</b>	<b>1,309</b>	<b>509</b>	<b>1,288</b>	<b>3,393</b>			
<b>TXU Energy</b>											
<i>Pollution Control Rev Bonds</i>											
<i>Brazos River Authority:</i>											
3.00% Series 1994A (a)	2029	Fixed					39	39		05/01/05	100.00
5.40% Series 1994B (a)	2029	Fixed					39	39		05/01/06	100.00
5.40% Series 1995A (a)	2030	Fixed					50	50		05/01/06	100.00
5.05% Series 1995B (a)	2030	Fixed					118	118		06/19/06	100.00
7.70% Series 1999A	2033	Fixed					111	111		04/01/33	100.00
6.75% Series 1999B (a)	2034	Fixed					16	16		04/01/13	100.00
7.70% Series 1999C	2032	Fixed					50	50		03/01/32	100.00
4.95% Series 2001A (a)	2030	Fixed					121	121		04/01/04	100.00
4.75% Series 2001B (a)	2029	Fixed					19	19		11/01/06	100.00
5.75% Series 2001C (a)	2036	Fixed					274	274		11/01/11	100.00
1.25% Series 2001D	2033	Floating					271	271		11/01/04	100.00
1.18% Series 2001I	2036	Floating					63	63		12/01/36 (e)	100.00
1.25% Series 2002A	2037	Floating					61	61		05/01/37	100.00
6.75% Series 2003A (a)	2038	Fixed					44	44		04/01/13	100.00
6.30% Series 2003B	2032	Fixed					39	39		07/01/32	100.00
6.75% Series 2003C	2038	Fixed					72	72		10/01/13	101.00
5.40% Series 2003D (a)	2029	Fixed					31	31		10/01/14	100.00
<i>Sabine River Authority:</i>											
6.45% Series 2000A	2021	Fixed					51	51		06/01/10	100.00
5.50% Series 2001A (a)	2022	Fixed					91	91		11/01/11	100.00
5.75% Series 2001B (a)	2030	Fixed					107	107		11/01/11	100.00
5.80% Series 2003A	2022	Fixed					12	12		07/01/22	100.00
6.15% Series 2003B	2022	Fixed					45	45		08/01/13	101.00
<i>Trinity River Authority:</i>											
6.25% Series 2000A	2028	Fixed					14	14		05/01/13 (i)	101.00
5.00% Series 2001A (a)	2027	Fixed					37	37		11/01/06	100.00
<b>Total PCRBs</b>							<b>1,775</b>	<b>1,775</b>			
<i>Senior Notes</i>											
6.875% Senior Notes - Mining	2005	Fixed		30				30		08/01/05	100.00
6.125% Senior Notes	2008	Fixed					250	250		03/15/08 (e)	T+37.5
7.00% Senior Notes	2013	Fixed					1,000	1,000		03/15/13 (e)	T+50
<i>Other</i>											
Capital Lease Obligations	Various						13	13			
Other	Various						8	8			
Unamortized Prem and Disc							9	9			
<b>Total TXU Energy</b>				<b>30</b>			<b>3,055</b>	<b>3,085</b>			
<b>Oncor</b>											
<i>First Mortgage Bonds</i>											
8.25%	2004	Fixed	100					100		04/01/04(d)(f)	100.00
6.25%	2004	Fixed	121					121		10/01/04 (d)	100.00
6.75%	2005	Fixed		92				92		07/01/05 (d)	100.00
7.625%	2025	Fixed					215	215	102.69	07/01/05	102.42
7.375%	2025	Fixed					178	178	103.35	10/01/05	103.02
<i>Senior Secured Notes</i>											
6.375%	2012	Fixed					700	700		05/01/12 (e)	T+25
7.00%	2032	Fixed					500	500		05/01/32 (e)	T+30

See footnotes on next page.

**SCHEDULE OF LONG-TERM DEBT**  
**As of December 31, 2003**  
(\$ millions)

Issue	Year Due	Fixed/ Floating	2004	2005	2006	2007	2008 & Beyond	Total	Redemption Price at 12/31/03	Date of Next Redemption Price	Next Redemption Price
<b>Oncor</b>											
6.375%	2015	Fixed					500	500		(e)	T+30
7.25%	2033	Fixed					350	350		(e)	T+35
<i>Debentures</i>											
5.00%	2007	Fixed				200		200		(e)	T+20
7.00%	2022	Fixed					800	800		(e)	T+30
Unamortized Prem and Disc							(30)	(30)			
			221	92	-	200	3,213	3,726			
<b>Oncor Transition Bond Company<sup>(b)</sup></b>											
2.26% Series 2003	2007	Fixed				103		103		(g)	100.00
4.03% Series 2003	2010	Fixed					122	122		(g)	100.00
4.95% Series 2003	2013	Fixed					130	130		(g)	100.00
5.42% Series 2003	2015	Fixed					145	145		(g)	100.00
<b>Total Oncor</b>			<b>221</b>	<b>92</b>	<b>-</b>	<b>303</b>	<b>3,610</b>	<b>4,226</b>			
<b>US Holdings</b>											
<i>Senior Debentures</i>											
7.17%	2007	Fixed				10		10		08/01/07 (e)	100.00
<i>Notes</i>											
9.58%	2019	Fixed					70	70		(d)	
8.254%	2021	Fixed					67	67		(d)	
<i>Junior Subord Debentures</i>											
1.910%, Series D	2037	Floating					1	1		01/30/37 (e)	100.00
8.175%, Series E	2037	Fixed					8	8		02/01/07	104.09
<b>Total US Holdings</b>			<b>-</b>	<b>-</b>	<b>-</b>	<b>10</b>	<b>146</b>	<b>156</b>			
<b>TXU Gas</b>											
<i>Notes</i>											
6.375%	2004	Fixed	150					150		(c)	100.00
7.125%	2005	Fixed		150				150		02/15/05 (d)	100.00
6.564%, Remarketed Reset	2008	Fixed					125	125		07/01/05	100.00
Unamortized fair value adj							1	1			
<b>Total TXU Gas</b>			<b>150</b>	<b>150</b>	<b>-</b>	<b>-</b>	<b>126</b>	<b>426</b>			
<b>TXU Australia</b>											
<i>Notes</i>											
5.928%	2007	Floating				206		206			
6.395%, Tranche A Facility	2004	Floating	75					75			
6.318%, Tranche A Facility	2004	Floating	93					93			
6.395%, Tranche B Facility	2004	Floating	150					150			
6.395%, Tranche B Facility	2004	Floating	37					37			
6.395%, Tranche B Facility	2004	Floating	187					187			
6.600%, Tranche C Facility	2004	Floating	150					150			
7.00%, Medium Term Notes	2005	Fixed		150				150			
6.090%, Senior Notes	2006	Fixed			250			250			
6.34%, Senior Notes	2016	Fixed					100	100			
6.15%, Senior Notes	2013	Fixed					57	57			
6.15%, Senior Notes	2013	Fixed					243	243			
Unamortized Prem, Disc and fair value adjustments							17	17			
<b>Total TXU Australia</b>			<b>692</b>	<b>150</b>	<b>250</b>	<b>206</b>	<b>417</b>	<b>1,715</b>			
<b>Total Long-Term Debt</b>			<b>1,341</b>	<b>431</b>	<b>1,559</b>	<b>1,028</b>	<b>8,642</b>	<b>13,001</b>			

- (a) These bonds are in the multi-annual mode and are subject to mandatory tender prior to maturity on the mandatory remarketing date. On such date, the interest rate and interest rate period will be reset for the bonds.  
Brazos Series: 2001A – 2004; 1994A – 2005; 1994B, 1995A, 1995B, 2001B – 2006; 2001C – 2011; 1995B, 2003A- 2013; 2003D - 2014  
Sabine Series: 2001A, 2001B – 2011  
Trinity Series: 2001A – 2006
- (b) Bonds due in bi-annual installments through due date.  
(c) Redeemed 02/01/04  
(d) No redemption prior to maturity  
(e) Redeemable at any time – 30 days prior notice  
(f) Redeemed 04/01/04  
(g) Not redeemable unless 5% or less of initial principal balance is outstanding and only after last scheduled payment date.  
(h) Redeemable on not less than 30 days or more than 60 days upon occurrence of a Tax Event.  
(i) Subject to Extraordinary Mandatory Redemption Upon Determination of Taxability.

**SCHEDULE OF PREFERRED SECURITIES**  
**As of December 31, 2003**

(\$ millions)

Issue	Year Due	Fixed/ Floating	2004	2005	2006	2007	2008 & Beyond	Total	Redemption Price at 12/31/03	Date of Next Redemption Price	Next Redemption Price
<b>TXU Corp</b>											
<i>Preferred Securities</i>											
Capital I Trust, 7.25% <sup>(1)</sup>	2029	Fixed					237	237	100.00		
Capital II Trust, 8.70%	2034	Fixed					154	154		12/31/04	100.00
<i>Preference Stock, 7.24%</i>	Perpetual	Fixed						300			
<b>Total TXU Corp</b>			-	-	-	-	<b>391</b>	<b>691</b>			
<b>US Holdings</b>											
<i>Preferred Stock</i>											
\$4.00 Series - TPL	Perpetual	Fixed						3	102.00		
\$4.44 Series - TPL	Perpetual	Fixed						3	102.61		
\$4.56 Series - TPL	Perpetual	Fixed						5	112.00		
\$4.76 Series - TPL	Perpetual	Fixed						2	102.00		
\$4.84 Series - TPL	Perpetual	Fixed						2	101.79		
\$4.00 Series - TES	Perpetual	Fixed						7	102.00		
\$4.56 Series - TES	Perpetual	Fixed						2	112.00		
\$4.64 Series - TES	Perpetual	Fixed						3	103.25		
\$5.08 Series - TES	Perpetual	Fixed						3	103.60		
\$4.00 Series - DPL	Perpetual	Fixed						2	103.56		
\$4.24 Series - DPL	Perpetual	Fixed						2	103.50		
\$4.50 Series - DPL	Perpetual	Fixed						2	110.00		
\$4.80 Series - DPL	Perpetual	Fixed						2	102.79		
<b>Total US Holdings</b>			-	-	-	-	-	<b>38</b>			
<b>TXU Gas</b>											
<i>Preferred Stock</i>											
Series F, 4.61%	Perpetual	Floating						75			
<i>Preferred Securities</i>											
Capital I Trust, 2.51%	2028	Floating					155	155			
<b>Total TXU Gas</b>			-	-	-	-	<b>155</b>	<b>230</b>			
<b>TXU Energy</b>											
<i>Exchangeable Pref Memb Interests, 9.00% (net of unamort disc <sup>(2)</sup>)</i>											
	2012	Fixed					646	646			
<b>Total TXU Energy</b>			-	-	-	-	<b>646</b>	<b>646</b>			
<b>Total Preferred Securities</b>			-	-	-	-	<b>1,192</b>	<b>1,605</b>			

(1) Redeemed on 4/24/04

(2) Redeemed on 4/26/04

## CAPITALIZATION

(\$ millions)

	Years Ended December 31									
	2003	%	2002	%	2001	%	2000	%	1999	%
<b>CAPITALIZATION AND CURRENT DEBT</b>										
Short-Term Debt	97	0.5	2,324	11.2	1,914	8.5	2,379	10.6	2,596	11.4
Current Maturities	677	3.3	958	4.7	866	3.9	1,844	8.2	877	3.9
Long-Term Debt	12,324	60.7	10,954	52.9	10,920	48.7	8,583	38.3	9,311	40.9
<b>Total Debt <sup>(1)(2)</sup></b>	<b>13,098</b>	<b>64.5</b>	<b>14,236</b>	<b>68.8</b>	<b>13,700</b>	<b>61.1</b>	<b>12,806</b>	<b>57.1</b>	<b>12,784</b>	<b>56.2</b>
<b>Preferred Securities:</b>										
Preferred Securities	546	2.7	546	2.6	547	2.4	1,423	6.3	1,423	6.2
Preference Stock	300	1.4	300	1.5	300	1.3	300	1.3	-	-
Preferred Stock of Subsidiaries	113	0.6	211	1.0	211	1.0	211	1.0	211	1.0
Exchangeable Preferred Membership Interests	646	3.2	639	3.1	-	-	-	-	-	-
<b>Total Preferred Securities</b>	<b>1,605</b>	<b>7.9</b>	<b>1,696</b>	<b>8.2</b>	<b>1,058</b>	<b>4.7</b>	<b>1,934</b>	<b>8.6</b>	<b>1,634</b>	<b>7.2</b>
<b>Common Stock Repurchasable under Equity Forward Contracts</b>	<b>-</b>	<b>0.0</b>	<b>-</b>	<b>0.0</b>	<b>-</b>	<b>0.0</b>	<b>190</b>	<b>0.8</b>	<b>-</b>	<b>0.0</b>
<b>Common Stock:</b>										
Balance at the beginning of year	7,995		6,560		6,360		6,795		6,940	
Dividend reinvestment and Employee benefits	33		46		21		9		6	
Other capital stock transactions, net	<sup>(3)</sup> (7,980)		1,389		179		(444)		(151)	
Balance at the end of the year	48		7,995		6,560		6,360		6,795	
<b>Common stock – Equity Forward Contracts</b>	<b>-</b>		<b>-</b>		<b>-</b>		<b>(190)</b>		<b>-</b>	
<b>Retained Earnings:</b>										
Balance at the beginning of year	(2,900)		1,863		1,817		1,691		1,448	
Net income	582		(4,210)		677		916		985	
Common stock dividends	( 160)		( 533)		( 625)		( 625)		( 647)	
Preference stock dividends	( 22)		( 22)		( 22)		( 12)		-	
Other capital stock transactions, net	2		2		16		( 153)		( 95)	
Balance at the end of the year	(2,498)		(2,900)		1,863		1,817		1,691	
<b>Accumulated Other –Comprehensive Income</b>	<b>(28)</b>		<b>(440)</b>		<b>(767)</b>		<b>(511)</b>		<b>(152)</b>	
<b>Total Common Stockholders' Equity</b>	<b>5,619</b>	<b>27.6</b>	<b>4,766</b>	<b>23.0</b>	<b>7,656</b>	<b>34.2</b>	<b>7,476</b>	<b>33.5</b>	<b>8,334</b>	<b>36.6</b>
<b>TOTAL CAPITALIZATION</b>	<b>20,322</b>	<b>100.0</b>	<b>20,698</b>	<b>100.0</b>	<b>22,414</b>	<b>100.0</b>	<b>22,406</b>	<b>100.0</b>	<b>22,752</b>	<b>100.0</b>
Embedded Interest Cost of Long-Term Debt	6.5%		6.9%		6.2%		7.5%		6.9%	
Embedded Interest Cost on Long-Term Debt Held by Subsidiary Trusts	6.4%		7.8%		7.8%		9.8%		8.1%	
Embedded Dividend Cost on Preferred Stock of Subsidiaries	9.7%		6.5%		6.5%		7.0%		7.0%	

(1) Includes equity-linked securities of \$1.44 billion (2003 and 2002), \$1.35 billion (2001), and \$700 million (2000 and 1999).

(2) Debt amounts shown are from balance sheet. Securitization bond amounts totaled \$500 million at the end of 2003 and are treated off-credit in credit reviews

(3) Reflects \$8.0 billion reclassification from Common Stock to Additional Paid in Capital approved by shareholders in February 2004.

## COMMON STOCK DATA

(\$ millions except per share amounts)	2003	2002	2001	2000	1999
<b>Earnings Per Share (before extraordinary items and cumulative effect of changes in accounting principles)</b>					
Basic	\$ 2.22	\$ 0.58	\$ 2.11	\$ 2.51	\$ 2.48
Dilutive	\$ 2.03	\$ 0.58	\$ 2.11	\$ 2.51	\$ 2.48
<b>Earnings Per Share</b>					
Basic	\$ 1.74	\$ (15.23)	\$ 2.52	\$ 3.43	\$ 3.53
Dilutive	\$ 1.62	\$ (15.23)	\$ 2.52	\$ 3.43	\$ 3.53
<b>Shares Outstanding (Year End)</b>					
Weighted Average Shares Outstanding					
Basic	322	278	259	264	279
Dilutive	379	278	259	264	279
<b>Dividends Paid</b>					
Dividends Paid	\$ 6.52	\$ 6.21	\$ 634	\$ 634	\$ 639
Dividends Paid (Per Share)	\$ 0.50	\$ 2.40	\$ 2.40	\$ 2.40	\$ 2.30
Dividend Payout Ratio	30.9%	–	95.2%	70.0%	65.2%
Book Value (Per Share)	\$ 17.34	\$ 14.80	\$ 28.88	\$ 28.97	\$ 30.15
<b>Historical Stock Prices:</b>					
<b>Market Price (Per Share)</b>					
High	\$ 23.96	\$ 57.05	\$ 50.00	\$ 45.25	\$ 47.19
Low	\$ 15.00	\$ 10.10	\$ 34.81	\$ 25.94	\$ 32.75
Close	\$ 23.72	\$ 18.68	\$ 47.15	\$ 44.31	\$ 35.56

## CREDIT RATINGS<sup>(1)</sup> (as of April 28, 2004)

	Moody's	S&P	Fitch
<b>TXU Corp</b>			
Senior Unsecured	Ba1	BBB-	BBB-
Preferred Securities	Ba2	BB+	BB+
Preference Stock	Ba3	BB+	BB+
<b>US Holdings</b>			
Unsecured	Baa3	BBB-	BBB-
<b>Oncor</b>			
Secured	Baa1	BBB	BBB+
Unsecured	Baa2	BBB-	BBB
<b>TXU Energy</b>			
Senior Unsecured	Baa2	BBB	BBB
<b>TXU Gas</b>			
Senior Unsecured	Baa3	BBB	BBB-
Preferred Securities	Ba1	BB+	BB+
Preferred Stock	Ba2	BB+	BB+
<b>TXU Australia</b>			
Senior Unsecured	Baa2	BBB	BBB-

<sup>(1)</sup> 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 agency decides that circumstances warrant such a change.

## LIQUIDITY – NORTH AMERICA

(\$ millions)	Expiration Date	Years Ended December 31		
		2003	2002	2001
Cash and Cash Equivalents		875	1,574	216
Credit Facilities:		<b>Available Capacity</b>		
\$150 million	Dec. 2003	–	150	–
\$1.4 billion	Feb. 2005	1,356	–	1,400
\$1.4 billion (a)	Feb. 2005	–	–	932
\$450 million	Feb. 2005	450	–	–
\$400 million	May 2005	400	–	–
\$500 million	Aug. 2008	78	–	–
\$700 million (b)	Apr. 2005	–	–	–
\$1 billion (b)	Apr. 2005	–	–	–
\$300 million (b)	Apr. 2005	–	–	–
<b>Total Available Liquidity</b>		<b>3,159</b>	<b>1,724</b>	<b>2,548</b>

(a) Previously known as US Credit Facility B, which no longer exists.

(b) As indicated in April 2004.

## CAPITAL EXPENDITURES

(\$ millions)	2003	2002	2001
Energy	163	285	327
Oncor <sup>(1)</sup>	658	621	825
Australia	120	82	65
Corp and Other	15	15	26
<b>Total</b>	<b>956</b>	<b>1,003</b>	<b>1,243</b>

<sup>(1)</sup> Comprising Oncor Electric Delivery and TXU Gas

# **DEFINITIONS**

## **OPERATIONAL PERFORMANCE MEASURES**

**Base Load** – Generation category including both nuclear and lignite/coal, fired generation representing the most cost efficient generation in an area that is generally economical to run at all times.

**CAIDI** – Customer Average Interruptible Duration Index

**Fuel Factor** – The initial Price to Beat fuel factors, set in 2001, were based on typical integrated utility fuel filings, adjusted for the 10-day rolling average price of the NYMEX 12-month strip for the last 5 trading days prior to, and first 5 trading days after September 11, 2001. Prior to revisions in the Price to Beat rule in April 2003, increases in the fuel factors were permitted only after a 4% increase in the 10-day rolling average price of the NYMEX 12-month strip. Currently, increases must reflect at least a 5% increase in the 20-day rolling average of the NYMEX 12-month strip

**Heat Rate** – A measure of generating station thermal efficiency, generally expressed in Btu per new KWh. It is computed by dividing the total Btu content of fuel burned for electric generation by the resulting net KWh generation.

**IDR** – An IDR meter is an interval data recorder. It records a customer's electrical demand and consumption in 15 minute intervals (or 96 times a day).

**Installed Capacity** – The full-load continuous rating of a generator under specified conditions as designated by the manufacturer.

**LBM** – The Large Business Market is comprised of customers having aggregate demands of one megawatt or greater (annual spend generally \$250K or higher). LBM customers span commercial, industrial, government, and education sectors. LBM customers typically sign contracts with 1 to 5 years terms that are transacted through a direct sales force and channel partners.

**Lost Workday Incident Rate** – Number of lost workday cases per 200,000 employee hours.

**Native Market** – An Affiliated Retail Electric Provider's (AREP) native market is the geographic boundaries of the area and associated retail customers served by the former integrated utility from which an AREP was created.

**Net Customer Change** – Gross customer gains due to move ins and win-back plus the gross customer losses caused by switching, move-outs and disconnects.

**Net Generation** – The amount of electric energy produced by the generating units in a generating station, less the kilowatt-hours consumed for that station's use.

**Non-IDR** – A non-IDR meter is a meter that records a customer's electrical demand and consumption over a monthly period.

**SAIDI** – (System Average Interruptible Duration Index) – Defined as the number of minutes the average customer is out of service in a year. Determined by summing the customer-minutes off for each interruption during a specified time period and dividing the sum by the average number of customers served during the period.

**SAIFI** – (System Average Interruptible Frequency Index) – Defined as the number of times in a year that the average customer experiences an interruption (non-transient) to service. Determined by dividing the total number of customers interrupted in a time period by the average number of customers served.

**SMB** – Small and Medium Business

## **FINANCIAL PERFORMANCE MEASURES**

**Available Capacity** – Amount of undrawn capacity on corporate and subsidiary short-term borrowing facilities.

**Book Value Per Share** – Common equity divided by end of period shares outstanding.

**Liquidity** – Measures how easily assets can be turned into cash to pay bills, pay dividends to shareholders, and make future investments in the growth of the business.

**Preferred Securities** – Sum of preference stock, exchangeable preferred membership interests, and preferred stock of subsidiaries.

**Total Debt** – Sum of short-term and long-term debt and capital leases on the balance sheet less non-recourse debt.

**Total Liquidity** – Sum of cash and available capacity.

**INVESTOR INFORMATION**

The Board of Directors meet quarterly, generally on the third Friday of February, May, August and November. The 2004 Annual Shareholders Meeting will be held on Friday, May 21st at the Fort Worth Convention Center, 1201 Houston Street, Fort Worth, Texas. The meeting will commence at 9:30 a.m. (CDT).

**SHAREHOLDER NEWS**

TXU’s quarterly earnings results, dividend action, and other news and information of investor interest may be obtained by calling 1-800-828-0812, emailing shareholder@txu.com, or accessing the company’s website at www.txucorp.com. Dividend information will be updated according to the declaration schedule.

For copies of TXU’s 10-K and 10-Q reports filed with the Securities & Exchange Commission or for other investor information, access the website at www.txucorp.com, call 1-800-828-0812 or write to:

TXU Corp.  
Investor Relations  
Energy Plaza  
1601 Bryan Street  
Dallas, Texas 75201

Securities analysts and representatives of financial institutions may contact Tim Hogan, Director of Investor Relations at 1-214-812-4641 or thogan@txu.com regarding TXU’s financial and operating performance.

**SHAREHOLDERS ACCOUNT INFORMATION**

TXU Shareholder Services is TXU’s transfer agent, registrar, dividend paying agent and direct stock purchase and dividend reinvestment plan administrator for TXU Corp. common stock. Shareholders of record with questions about lost or stolen certificates, lost or missing dividend checks or notifications of change of address should contact TXU Shareholder Services.

**COMMON STOCK INFORMATION**

The Company’s common stock is listed on the New York, Chicago and Pacific stock exchanges under the symbol “TXU.” The TXU share price is reported daily in the financial press under “TXU” in most listings of New York Stock Exchange securities. TXU is a member of the following indices: S&P 500, S&P 500 Electric Utilities Index, the Dow Jones Utilities Average, and Philadelphia Utility Index, among others. At year end 2003, there were 323,883,092 shares of TXU common stock outstanding. Shareholders of record totaled 65,146.

**DIVIDEND PAYMENTS**

The entire amount of dividends paid during 2003 was a non-taxable distribution, or return of capital. The Board of Directors declares dividends quarterly and sets the record and payment dates. Subject to Board discretion, those dates for 2004 are:

Declaration Date	Record Date	Payment Date
February 20, 2004	March 5, 2004	April 1, 2004
May 21, 2004	June 4, 2004	July 1, 2004
August 20, 2004	September 3, 2004	October 1, 2004
November 19, 2004	December 3, 2004	January 3, 2005

Quarterly dividend payments (in cents per share):

Quarter	2003	2002	2001	2000	1999
1	12.5	60.0	60.0	60.0	57.5
2	12.5	60.0	60.0	60.0	57.5
3	12.5	60.0	60.0	60.0	57.5
4	12.5	60.0	60.0	60.0	57.5

**DIVIDEND REINVESTMENT/STOCK PURCHASE**

TXU offers an automatic Dividend Reinvestment and Stock Purchase Plan administered by TXU Shareholder Services. The plan is designed to provide TXU shareholders and other investors with a convenient and economical method to purchase shares of the company’s common stock. The plan also accommodates payments of up to \$250,000 per year for the purchase of TXU common shares. First-time investors may make an initial minimum purchase of \$500. Contact TXU Shareholder Services by telephone or visit TXU’s website for information and an enrollment form.

**TXU COMMON STOCK PRICES**

The high and low trading prices for each quarterly period in 2003 and 2002 were as follows (in dollars per share):

Quarter	2003		2002	
	High	Low	High	Low
1	20.37	15.00	55.20	46.27
2	22.87	17.54	57.05	48.81
3	23.70	19.58	51.85	33.65
4	23.96	20.87	40.99	10.10

[www.txucorp.com](http://www.txucorp.com)