RAILROAD COMMISSION OF TEXAS

OFFICE OF GENERAL COUNSEL

TXU GAS COMPANY STATEMENT OF INTENT TO CHANGE RATES IN THE COMPANY'S STATEWIDE GAS UTILITY SYSTEM	**§ § § §**	**GAS UTILITIES DOCKET NO. 9400**

PROPOSAL FOR DECISION

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I. INTRODUCTION

On May 23, 2003, TXU Gas Company, a direct subsidiary of TXU Corp.,[1] filed with the Railroad Commission of Texas (Commission) its statement of intent to change rates in the utility's statewide gas utility system[2] pursuant to TEX. UTIL. CODE ANN. (TUC), Title 3, Subtitle A (Gas Utility Regulatory Act, §§101.001, *et seq.*); TEX. UTIL. CODE ANN., Title 3, Subtitle B (Regulation of Transportation and Use, §§121.001, *et seq*.); and, specifically, TEX. UTIL. CODE ANN., Chapter 104, Subchapters A-C, §§104.101-104.111 (Vernon 1998 and Supp. 2003).

TXU's application is the first of its kind. TXU requested system-wide rates so that all customers of a particular customer class would be charged the same rate. TXU stated that the utility's customers would benefit from this proposed rate structure by reducing rate case expenses, making rates more transparent and easier to understand, ensuring that similarly-situated customers using similar services pay uniform rates, equalizing rate effects of additional investment across the system, and confirming that each customer class bears an equitable share of TXU's cost of service and no customer class unfairly subsidizes another.[3]

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1 TXU Exhibit 11at 14.
2 TXU Exhibit 1 at 1.
3 TXU Exhibit 11at 9.

TXU proposed rates for six customer classes. Four classes of service are applicable to well-head to burner-tip service while two classes of service are applicable to customers using only Pipeline facilities. For efficient case management, the Examiners divided the hearing into three phases: (1) Cost of Service, (2) Allocation/Rate Design, and (3) Miscellaneous Issues.

II. PROCEDURAL HISTORY AND NOTICE

A. Procedural History

Consolidations

On May 23, 2003, TXU filed with the Railroad Commission of Texas (Commission) its statement of intent to change rates in TXU Gas's statewide gas utility system. The Commission assigned the statement of intent to Gas Utility Docket (GUD) 9400. Also on May 23, 2003, TXU simultaneously filed its statement of intent in each municipality where the utility provides natural gas service. Municipalities have original jurisdiction over the rates charged to customers located within city limits. TXU thereafter filed a series of petitions for review (or appeals) of the decisions of the governing bodies of the municipalities. The appeals were consolidated into GUD 9400 as follows:

> Gas Utilities Docket (GUD) 9398, *Appeal of TXU Gas Company from the Action of Municipalities Denying a Rate Request*, filed by TXU on June 16, 2003, and consolidated with GUD 9400 on July 22, 2003;[4]
>
> GUD 9437, *Petition for Review of TXU Gas Company from the Actions of Municipalities Denying a Rate Request*, filed by TXU on July 7, 2003, and consolidated with GUD 9400 on July 22, 2003;[5]
>
> GUD 9442, *Petition for Review of TXU Gas Company from the Actions of Municipalities Denying a Rate Request*, filed by TXU on July 14, 2003, and consolidated with GUD 9400 on July 22, 2003;[6]
>
> GUD 9444, *Petition for Review of TXU Gas Company from the Actions of Municipalities Denying a Rate Request*, filed by TXU on June 27, 2003, and consolidated with GUD 9400 on July 22, 2003;[7]
>
> GUD 9448, *Petition for Review of Municipal Rate Decisions and Expedited Motion to Consolidate*, filed by TXU on August 6, 2003, and consolidated with GUD 9400 on August 13, 2003;[8]
>
> GUD 9450, *Petition for Review of TXU Gas Company from the Actions of Municipalities Denying a Rate Request and Expedited Motion to Consolidate*, filed by TXU on August 13, 2003, and consolidated with GUD 9400 on August 14, 2003;[9]

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[4] TXU Exhibit 1A.
[5] TXU Exhibit 1B.
[6] TXU Exhibit 1C.
[7] TXU Exhibit 1D.
[8] TXU Exhibit 1E.
[9] TXU Exhibit 1F.

GUD 9451, *Petition for Review of Municipal Rate Decisions and Expedited Motion to Consolidate*, filed by TXU on August 22, 2003, and consolidated with GUD 9400 on August 26, 2003;[10]

GUD 9452, *Petition for Review of TXU Gas Company from the Actions of Municipalities Denying a Rate Request and Expedited Motion to Consolidate*, filed by TXU on September 3, 2003, and consolidated with GUD 9400 on September 9, 2003;[11]

GUD 9456, *Petition for Review of TXU Gas Company from the Actions of Municipalities Denying a Rate Request and Expedited Motion to Consolidate,* filed by TXU on September 10, 2003, and consolidated with GUD 9400 on September 11, 2003;[12]

GUD 9459, *Petition for Review of TXU Gas Company from the Actions of Municipalities Denying a Rate Request and Expedited Motion to Consolidate,* filed by TXU on September 29, 2003, and consolidated with GUD 9400 on October 6, 2003. [13]

On August 5, 2003, the Commission decided to consider GUD 9435, *Request of Texas A&M University for Establishment of Transportation Rate on TXU Gas Company* separately from GUD 9400.[14]

<u>*Intervening Parties*</u>
The Allied Coalition of Cities (ACC) intervened on behalf of the following municipalities:
Abilene, Addison, Allen, Alvarado, Angus, Argyle, Arlington, Athens, Austin, Bedford, Bellmead, Bells, Benbrook, Blossom, Blue Ridge, Bowie, Bridgeport, Brownwood, Bryan, Burkburnett, Burleson, Caddo Mills, Carrollton, Cedar Hill, Celina, Cleburne, Clyde, College Station, Colleyville, Comanche, Coppell, Corinth, Corral City, Crandall, Crowley, Dalworthington Gardens, Denison, DeSoto, Duncanville, Early, Eastland, Edgecliff Village, Ennis, Euless, Everman, Fairview, Farmers Branch, Farmersville, Fate, Flower Mound, Forest Hill, Fort Worth, Frisco, Gainesville, Garland, Garrett, Grand Prairie, Grapevine, Haltom City, Harker Heights, Haskell, Haslet, Henrietta, Highland Park, Highland Village, Honey Grove, Howe, Hurst, Irving, Justin, Kaufman, Keller, Kennedale, Kerrville, Killeen, Krum, Lake Worth, Lancaster, Lewisville, Lincoln Park, Little Elm, Malakoff, Mansfield, McKinney, Megargel, Mesquite, Midlothian, Murphy, Newark, Nocona, North Richland Hills, Northlake, Ovilla, Palestine, Pantego, Paris, Parker, Pecan Hill, Petrolia, Plano, Ponder, Pottsboro, Prosper, Putnam, Red Oak, Richardson, Richland Hills, Robinson, Rockwall, Rowlett, Sachse, Saginaw, San Angelo, Seagoville, Sherman, Snyder, Southlake, Springtown, Stamford, Stephenville, Sulphur Springs, Sweetwater, The Colony, Throckmorton, Trophy Club, University Park, Vernon, Waco, Watauga, Waxahachie, Westworth Village, White Settlement, Whitesboro, Wichita Falls, Woodway, and Wylie.

The Association of TXU Municipalities (ATM) intervened on behalf of the following municipalities:
Balch Springs, Bandera, Belton, Bertram, Bremond, Burnet, Caldwell, Cameron, Cedar Park, Cisco, Clifton, Coleman, Commerce, Copperas Cove, Corsicana, De Leon, Denton, Dublin, Electra, Fredricksburg, Frost, Gatesville, Goldthwaite, Granbury, Grandview, Greenville, Groesbeck, Hamilton,

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[10] TXU Exhibit 1G.
[11] TXU Exhibit 1H.
[12] TXU Exhibit 1I.
[13] TXU Exhibit 1J.
[14] Open Meeting Tr. at 62 (Aug. 5, 2003). Notice of Dismissal was issued in GUD 9435 (Dec. 9, 2003).

Hillsboro, Holland, Lake Dallas, Lampasas, Leander, Lexington, Llano, Lometa, Longview, Manor, Mart, McGregor, Mexia, Pflugerville, Ranger, Rockdale, Rogers, Round Rock, San Saba, Santa Ana, Seymour, Somerville, Thorndale, Trinidad, West, and Whitney.

The following municipalities ceded jurisdiction to the Commission:
Abbott, Anson, Bardwell, Blackwell, Blanket, Bronte, Calvert, Chandler, Como, Coolidge, Cooper, Covington, Cumby, Emory, Ferris, Forney, Franklin, Gustine, Hamlin, Hawley, Hearne, Hubbard, Italy, Ladonia, Lipan, Little River-Academy, Lott, Lueders, Madisonville, Marble Falls, Melissa, Merkel, Midway, Moody, New Chapel Hill, Normangee, O'Brien, Pecan Gap, Penelope, Point, Robert Lee, Roby, Roxton, Rule, Sadler, Sanctuary, Southmayd, Talty, Trent, Tyler, Van Alstyne, Weinert, Whitehouse, Wixon Valley, and Wolfe City.

In addition, the following parties also intervened: the City of Dallas (Dallas); Industrial Gas Users (IGU); Chaparral Steel Midlothian, L.P. (Chaparral); Brazos Electric Power Cooperative, Inc. (Brazos); Garland Power & Light (GP&L); West Texas Gas, Inc. (WTG); CoServ Gas. Ltd. (CoServ); the Texas General Land Office (GLO); the United State Department of Defense and Other Federal Executive Agencies (DoD); the State of Texas through the Attorney General's Office Consumer Protection Division (State of Texas); and Staff of the Railroad Commission of Texas (Staff).

TXU and CoServ negotiated an agreement whereby CoServ's existing contract was extended for five years.[15] Therefore, on December 11, 2003, CoServ's motion to withdraw as an intervening party was granted.[16] On the first day of the hearing, TXU and GLO announced settlement.[17] On February 20, 2004, the Examiners granted GLO's February 19, 2004, motion to be dismissed as a party to GUD 9400.[18]

Suspension Order
On June 24, 2003, in accordance with TEX. UTIL. CODE ANN. (TUC) §104.107(a)(2) (Vernon 1998 and Supp. 2003), the Commission suspended the operation of the proposed rate schedule for a period of one hundred fifty (150) days from the date on which the rates would otherwise become effective.[19]

Quarterly Rate Case Expenses
On August 5, 2003, the Commission ruled that TXU would provide to intervening municipalities quarterly reimbursement for eighty percent of rate case expenses.[20]

Severance of Certain Issues
To allow for further consideration of the issues, the following four dockets were created on October 9, 2003: (1) Proposed Curtailment Order, Rate Schedule 34 in Volume 3 of TXU Gas Company's Statement of Intent, GUD 9460, *Curtailment Issues Severed from Docket No. 9400*; (2) Proposed Service Rules and Regulations, Rate Schedules 21 – 27 in Volume 3 of TXU Gas Company's Statement of Intent, GUD 9461,

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15 Tr. Vol. 1 at 44 (Jan. 26, 2004).
16 Examiners' Letter No. 29 (Dec. 11, 2003).
17 Tr. Vol. 1 at 16 and 42-44 (Jan. 26, 2004).
18 Tr. Vol. 18 at 43, Line 6. *See* also Tr. Vol. 1 at 16, Lines 9-10 (Jan. 26, 2004) where GLO and TXU announced a settlement agreement in principle.
19 Commission Order (June 24, 2003).
20 Open Meeting Tr. at 50-53 (Aug. 5, 2003); Commission Order (Feb. 10, 2004).

Service Rules and Regulations Severed from Docket No. 9400; (3) Proposed Rate LEP - Line Extension Policy, Rate Schedule 15 in Volume 3 of TXU Gas Company's Statement of Intent, GUD 9462, *Rate LEP Severed from Docket No. 9400*; and (4) Proposed Rider CIAF - Capital Investment Adjustment Factor, Rider 18 in Volume 3 of TXU Gas Company's Statement of Intent, GUD 9463, *Rider CIAF Severed from Docket No. 9400.* [21] On March 23, 2004, the Commission severed rate case expenses into GUD No. 9517, *Rate Case Expenses Severed from Gas Utilities Docket No. 9400.*

<u>*Motions to Dismiss*</u>
On November 13, 2003, the Commission considered but took no action regarding parties' appeal of the Examiners' denial of motions to dismiss that were based upon municipalities' non-action.[22]

Prehearing conferences were held July 14, 2003; July 30, 2003; September 17, 2003; December 3, 2003; December 16, 2003; December 30, 2003; January 7, 2004; January 14, 2004; and January 21, 2004. Notice of Hearing was issued January 15, 2004.[23] The Hearing on the Merits began January 26, 2004. Parties were not aligned. Witnesses were examined individually rather than in panels. The Hearing on the Merits closed on February 20, 2004. The evidentiary record was closed on April 20, 2004.

B. Notice

The Gas Utility Regulatory Act, Subtitle 3, Chapters 101-105 of the Texas Utilities Code (TUC),[24] requires gas utilities to " . . . publish, in conspicuous form, notice to the public of the proposed increase once each week for four successive weeks in a newspaper having general circulation in each county containing territory affected by the proposed increase . . . . "[25] From May to July, 2003, TXU published notice once each week for four consecutive weeks in newspapers of general circulation in each county in which TXU Gas Company provides gas service. In addition, TXU mailed notice to each industrial customer in the utility's statewide gas utility system.[26]

TUC §104.102 also requires that a gas utility may not increase its rates unless the utility files a statement of its intent with the regulatory authority that has original jurisdiction over those rates at least 35 days before the effective date of the proposed increase. The utility is required to mail or deliver a copy of the statement of intent to the appropriate officer of each affected municipality.[27] On or about May 23, 2003, TXU filed with each municipality located in the system a statement of intent to increase rates for all customers. The statement of intent filed with each municipality is the same statement of intent that was filed at the Commission.[28]

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[21] Examiners' Letter No. 14 (Oct. 9, 2003); Examiners' Letter No. 17 (Oct. 16, 2003); Examiners' Letter No. 19 (Oct. 27, 2003); and Open Meeting Tr. at 36 (Nov. 13, 2003).
[22] Open Meeting Tr. at 33 (Nov. 13, 2003).
[23] The Notice of Hearing was issued in accordance with the requirements of TEX. GOV'T CODE §2001.052 (Vernon 2000 and Supp. 2004) and 16 TEX. ADMIN. CODE §1.45 (1991).
[24] Gas Utility Regulatory Act, TEX. UTIL. CODE ANN. (TUC), Subtitle A, §§101.001 - 121.057 (Vernon 1998 and Supp. 2004).
[25] TUC §104.103 (Vernon 1998).
[26] TXU Exhibit 3.
[27] TUC §104.102 (Vernon 1998 and Supp. 2004).
[28] TXU Exhibits 1A, p.2; 1B, p.2; 1C, p.2; 1D, p.2; 1E, p.2; 1F, p.2; 1G, p.2; 1H, p.2; 1I, p.2; and 1J, p.2.

TXU's Position

TXU argued that the notice issues raised by Dallas in its closing argument were dismissed by the Examiners in Examiners' Letter No. 9 on September 4, 2003.[29] TXU argued that the notice issues raised by ATM were similarly dismissed by the Examiners.[30]

With respect to the arguments raised by WTG, TXU noted that WTG is a transportation customer of TXU Gas, and that WTG received notice not only by publication but also by direct mail.[31] TXU noted that TUC §104.103 only requires TXU to provide notice to its customers, and does not require TXU to provide notice to the customers of TXU's customers.[32] TXU argued that it would be impossible for TXU to identify the customers of its customers or to know how their customers' rates are structured.[33]

WTG's Position

WTG argued that TXU failed to comply with TUC §104.103, which states that a "gas utility shall publish, in conspicuous form, notice to the public of the proposed increase once each week for four successive weeks in a newspaper having general circulation in each county containing territory affected by the proposed increase." WTG's position is that TXU was obligated to publish notice of its proposed rate increase in Concho County, Texas; Sutton County, Texas; and McCulloch County, Texas, but did not. WTG reasoned that because WTG, a customer of TXU, serves customers in these counties, WTG's customers would be affected by TXU's proposed rate increase.[34]

The existence of two Firm Transportation and Storage Agreement contracts between WTG and TXU formed the basis for WTG's position. WTG maintained that Contract Numbers 3319 and 3349 contain specific reference to Concho County, Sutton County, and McCulloch County. In addition, WTG argued that because TXU is aware WTG's tariffs that govern service to its customers in these counties contain purchase gas agreement clauses that allow WTG to pass to its customers increases in gas cost. TXU must publish notice of its proposed rate increase in Concho County, Sutton County, and McCulloch County.[35]

WTG qualified its position by stating that notice was required in Concho County, Sutton County, and McCulloch County only if Contract Numbers 3319 and 3349 are treated as city gate sales. WTG attempted to negotiate with TXU that if TXU will classify these contracts in Rate PT, Pipeline Transportation, then WTG can agree with TXU's argument that the TUC does not require TXU to provide notice to the customers of TXU's customers.[36]

WTG also cited TXU's failure to send a Statement of Intent to the City of Eden (Concho County), the City of Sonora (Sutton County), and the City of Brady (McCulloch County) as further evidence of no legal notice being provided to all territory affected by TXU's proposed rate increase.[37]

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[29] TXU Reply Brief at 3, (Mar. 17, 2004)
[30] TXU Reply Brief at 4 (Mar. 17, 2004).
[31] TXU Initial Brief at 6 (March 8, 2004).
[32] TXU Initial Brief at 6 (March 8, 2004).
[33] TXU Initial Brief at 6 (March 8, 2004).
[34] WTG Reply Brief at 3-7 (March 22, 2004).
[35] WTG Reply Brief at 3-7 (March 22, 2004).
[36] WTG Reply Brief at 7 (March 22, 2004).
[37] WTG Reply Brief at 7 (March 22, 2004).

Finally, WTG defended its late participation in this proceeding. WTG cited two sentences that appeared in TXU's executive summary: "As a matter of policy, we believe that the increase in Residential [sic] rates should be limited to 10 percent. There is a slight increase for the commercial class and no increase for other classes of customers." WTG determined from these two sentences that WTG would not be affected by TXU's proposed rate increase. Only later, after further review of the Statement of Intent, did WTG learn that transportation customers could be affected.[38]

Dallas's Position

Dallas argued that TXU's notice in this case was inadequate. Dallas argued that "[t]he purpose of notice in an administrative hearing is to afford those opposing the application a chance to prepare, and to avoid undue surprise."[39] Dallas observed that the published notice only gave notice of the average systemwide rate increase for residential and commercial.[40] Dallas pointed out that the percentage rate increase that appeared in the published notice for each customer class differed from the percentage rate increase that TXU filed with its Statement of Intent to the City of Dallas.[41] Thus, Dallas concluded that TXU's notice to customers was misleading and constituted a failure to disclose material facts.[42]

Dallas also argued that TXU's notice violated customers' procedural due process rights under the U.S. Constitution and the Texas Constitution.[43] Dallas argued that TXU's notice constituted state action because TXU published notice in compliance with a state law, and thus became an agent of the state.[44] Under Dallas's argument, customers' procedural due process rights were violated when municipal and state authorities acted on this defective notice.[45]

ATM's Position

ATM argued that TXU's notice was defective because it reflected the bundled rates or tariffs attached to the Statement of Intent filed with the municipalities and the Commission;[46] therefore, TXU did not provide notice of the proposed increase in Distribution rates or services.[47]

Examiners' Recommendation

The Examiners find that TXU's notice was sufficient and in compliance with the law. TUC §104.103 requires a gas utility to publish notice in each county containing territory affected by the proposed increase.[48] TXU published notice in each county in which it has customers. In addition, TXU mailed written notice to each of its industrial customers of the proposed rate increase.

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38 WTG Reply Brief at 4-6 (March 22, 2004).
39 Dallas Initial Brief at 11 (Mar. 8, 2004).
40 Dallas Initial Brief at 10 (Mar. 8, 2004).
41 Dallas Initial Brief at 11 (Mar. 8, 2004).
42 Dallas Initial Brief at 12 (Mar. 8, 2004).
43 Dallas Initial Brief at 12 (Mar. 8, 2004).
44 Dallas Initial Brief at 12 (Mar. 8, 2004).
45 Dallas Initial Brief at 12 (Mar. 8, 2004).
46 ATM Initial Brief at 11 (Mar. 8, 2004).
47 ATM Initial Brief at 11 (Mar. 8, 2004).
48 TEX. UTIL. CODE §104.103 (Vernon 1998).

The Examiners find that TUC §104.103 does not require a gas utility to publish notice in territories in which its customers have customers. Section 104.103 must be read not in isolation but rather in conjunction with all of the provisions of Chapter 104, relating to Rates and Services. For example, TUC §104.003 states that "[a] rate may not be unreasonably preferential, prejudicial, or discriminatory must be sufficient, equitable, and consistent in application to each *class of consumer*" (emphasis added). Clearly, the legislature is concerned with the proper application of a gas utility's rates to its customers, and not with their collateral impact downstream of the initial assessment. TUC §104.051 states that "[i]n establishing a gas utility's rates, the regulatory authority shall establish the utility's overall revenues at an amount that will permit the utility a reasonable opportunity to earn a reasonable return on the utility's invested capital used and useful in providing service to the public in excess of its reasonable and necessary operating expenses." To establish proper rates, a regulatory authority must establish a utility's revenue requirements and cost of service by evaluating a utility's customer base. To attempt to identify and account for the revenue that flows from a gas utility's customers' customers in calculating such ratemaking components would be difficult to impossible. Finally, the Examiners note that gas utilities are by statutory definition monopolies in the areas they serve. It is reasonable to require utilities to provide notice of proposed rate changes in their monopoly territory.

The Examiners conclude that the purpose of TUC §104.103 is to notify persons in a gas utility's geographic monopoly territory of the possibility of a change in the cost of a service, product, or commodity provided by the gas utility. Under TUC §104.103, this can be accomplished in several ways. At issue in this proceeding is whether the language in TUC §104.103(a) requiring a gas utility to publish notice "in each county containing territory affected by the proposed increase" requires the gas utility to publish notice in territories in which the utility does not directly provide service, but one of its gas utility customers serves customers. The Examiners answer this question in the negative for the above reasons.

The Examiners find that TXU properly gave notice to WTG of the proposed rate increase. TXU clearly provided its five-volume statement of intent to WTG.[49] Although not entirely clear from the record, it also appears that WTG received a separate written notice from TXU that was mailed by TXU to all of its industrial customers.[50]

The Examiners considered Dallas's arguments in City of Dallas's Motion to Dismiss for Defective Notice and Filing filed on August 20, 2003. In Examiners' Letter No. 9 issued on September 4, 2003, the Examiners denied City of Dallas's motion. The Examiners affirm their previous ruling.

The Examiners find that ATM's October 9, 2003, Motion to Dismiss was premised on the fact that TXU had bundled their rates in this proceeding. In the Examiners' October 27, 2003, letter denying ATM's motion, the Examiners concluded that all rates at issue in GUD 9400 were subject to the review by the Commission, under either its original or appellate jurisdiction. Although ATM did not at that time argue that TXU's notice was defective because of the proposed bundled rate structure, the Examiners find that an affected customer reading the published notice would conclude that the rates would be affected by this proposal, whether bundled or unbundled. The title of the notice is "Notice of Gas Rate Increase

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[49] WTG Exhibit No. 5 at 1.

[50] Tr. Vol. 1 at 85, 197; Tr. Vol. 16 at 45 - 47; TXU Exhibit 3.

Request."[51] The second sentence of the notice reads "[t]he proposed revisions to the respective rate schedules will impact *all classes of service* and *all fees and charges* presently being assessed by the Company *on its transmission and distribution systems*." (Emphasis added).[52] The Examiners find that a reasonable person reading this notice would conclude that TXU is proposing to increase Distribution rates.

III. JURISDICTION

The Commission has jurisdiction over TXU Gas Company and over the matters at issue in this proceeding pursuant to TEX. UTIL. CODE ANN. §§ 102.001, 103.003,103.051, 104.001, 121.051, 121.052 and 121.151. The Commission is vested with the authority and power to ensure compliance with the obligations of the Gas Utility Regulatory Act and to establish and regulate rates of gas utilities.[53] Gas utilities are affected with a public interest, are monopolies, and are therefore subject to the jurisdiction, control, and regulation of the Commission.[54]

The statutes and rules applicable to this proceeding included but were not limited to all sections of TEX. UTIL. CODE CHAPTERS 101, 102, 103, 104, and 121; and all Commission rules in 16 TEX. ADMIN. CODE, Chapters 1, 7, and 8; and 16 TEX. ADMIN. CODE §3.70 (2003).

A. Original

The Commission has exclusive original jurisdiction over the rates and services of a gas utility that distributes natural gas in areas outside a municipality and distributes natural gas in areas inside a municipality that surrenders its jurisdiction to the Commission. The Commission also has exclusive original jurisdiction over the rates and services of a gas utility that transmits, transports, delivers, or sells natural gas to a gas utility that distributes the gas to the public.[55] More specifically, the Commission has exclusive original jurisdiction over TXU's statement of intent filed at the Commission, the schedule of rates and services to be charged to customers that are served by TXU's Pipeline system, the schedule of rates and services to be charged to all environs customers served by TXU, and the schedule of rates and services to be charged to customers located in any municipality located in the TXU system that ceded jurisdiction to the Commission.[56] Consistent with the final Order in GUD 8664, the Commission also has jurisdiction over TXU's gas costs under TUC §§104.051, 104.055, and 104.152.

B. Appellate

The Commission has exclusive appellate jurisdiction to review an order or ordinance of a municipality exercising exclusive original jurisdiction regarding a statement of intent.[57] At the same time TXU filed its statement of intent with the Commission on May 23, 2003, TXU also filed with each municipality located in its system a statement of intent to increase rates for all customers. The statements of intent filed

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[51] TXU Exhibit 3.
[52] TXU Exhibit 3.
[53] TUC §101.002 (Vernon 1998 and Supp. 2004).
[54] TUC §101.002 (Vernon 1998 and Supp. 2004); TUC §121.051 (Vernon 1998).
[55] TUC §102.001(a) (Vernon 1998 and Supp. 2004).
[56] TUC §102.001(a) (Vernon 1998 and Supp. 2004) and §103.003 (Vernon Supp. 2004).
[57] TUC §102.001 (Vernon 1998 and Sup. 2004).

with each municipality are the same as that filed at the Commission. TXU appealed to the Commission the decisions of the governing bodies of the municipalities regarding TXU's statement of intent.[58]

C. Ceded by Municipalities

A municipality may have the Commission exercise exclusive original jurisdiction over gas utility rates, operations, and services in the municipality.[59] A party to a rate proceeding before a municipality's governing body may appeal the governing body's decision to the Commission.[60]

Intervening Parties' Positions

ATM argued that TXU Gas impinged on the Commission's original jurisdiction over areas outside municipalities when TXU Gas filed bundled rate cases before the municipalities.[61]

In addition, ATM argued that the Commission does not have appellate jurisdiction over any of the municipalities in this proceeding.[62] ATM relied on TUC §103.054(b) and §103.055(b) to conclude that the Commission does not have appellate jurisdiction over municipalities that took no action on or simply dismissed the proposed rate case filed by TXU with the municipalities because TXU may appeal only a "final decision" of a municipality.[63] ATM argued that dismissing or not acting on a rate case is not a "final decision" that may be appealed to the Commission.[64]

ATM also argued that bundling of gas rates is not permitted by the TEXAS UTILITIES CODE because a municipality has jurisdiction only over rates for the gas Distribution system.[65] ATM argued that the ATM municipalities dismissed TXU's rate case because TXU did not propose revisions to Distribution tariffs and schedules but rather bundled Distribution and Pipeline rates.[66] ATM also noted that TUC §102.151 requires TXU to file with a municipality the new Distribution rate schedules established in this proceeding.[67]

ATM argued that the effort by 55 municipalities to cede jurisdiction in this proceeding to the Commission was void because the municipal resolutions purporting to cede jurisdiction to the Commission were adopted after the rate case was filed in each municipality.[68] ATM found support for this position in TUC §103.003, which states "[a] municipality may not surrender its jurisdiction while a case involving the

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58 TXU Exhibits 1A, 1B, 1C, 1D, 1E, 1F, 1G, 1H, 1I, and 1J.
59 TUC §103.003 (Vernon Supp. 2004).
60 TUC §103.051 (Vernon 1998 and Supp. 2004).
61 ATM Initial Brief at 11 (Mar. 8, 2004).
62 ATM Initial Brief at 12 (Mar. 8, 2004).
63 ATM Initial Brief at 12 (Mar. 8, 2004).
64 ATM Initial Brief at 12 (Mar. 8, 2004); ATM Reply Brief at 10-11 (Mar. 17, 2004).
65 ATM Initial Brief at 14 (Mar. 8, 2004).
66 ATM Initial Brief at 13 (Mar. 8, 2004).
67 ATM Initial Brief at 15 (Mar. 8, 2004).
68 ATM Initial Brief at 17 (Mar. 8, 2004).

municipality is pending."[69] Therefore, ATM concluded that municipalities attempting to cede jurisdiction to the Commission should be treated the same as municipalities that took no action on TXU's proposed rate increase.[70]

Dallas concluded that any purported action by a municipality to surrender its jurisdiction to the Commission after the date the Statement of Intent was filed was void.[71] As a result, Dallas argued that TXU must charge its proposed rates in these municipalities because these municipalities did not act on TXU's proposal.[72] As for those municipalities that neither attempted to surrender jurisdiction to the Commission nor acted on TXU's proposal, Dallas concluded that TXU must charge its proposed rates in these municipalities.[73] To support its conclusion, Dallas cited TUC §104.107, which states that "[i]f the regulatory authority does not make a final determination concerning a schedule of rates before expiration of the applicable suspension period, the regulatory authority is considered to have approved the schedule."[74]

TXU's Position

TXU cited TUC §102.001 to support its position that the Commission has exclusive original jurisdiction over TXU's proposed rates in affected areas outside municipalities; in affected areas inside a municipality that surrendered its jurisdiction to the Commission; and to proposed rates that are to be charged to local distribution companies.[75] TXU argued that the Commission has exclusive appellate jurisdiction to conduct a de novo review of TXU's proposed rates for each affected municipality that denied TXU's request before the effective date; ceded jurisdiction to the Commission; took no action; dismissed the request; or suspended the effective date of the request and then later denied TXU's request.[76]

TXU noted that Dallas's arguments -- that the Commission lacked jurisdiction to review proposed rates for municipalities that ceded jurisdiction to the Commission or that took no action regarding TXU's request -- were rejected by the Examiners in August 2003.[77] Likewise, TXU noted that in October 2003, the Examiners dismissed the jurisdictional arguments raised by ATM in its Initial Brief.[78]

Examiners' Recommendation

In this proceeding, the Examiners found that the Commission has jurisdiction over TXU Gas Company and over the matters at issue in this proceeding pursuant to TEX. UTIL. CODE ANN. §§102.001, 103.003, 103.051, 104.001, 121.051, 121.052, and 121.151. ATM appealed Examiners' August 12,2003, Letter No. 6 that denied ATM's Motion to Dismiss. On November 13, 2003, the Commission considered ATM's appeal of the Examiners' denial of the motion to dismiss. ATM's motion was denied by operation of law.

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[69] ATM Initial Brief at 17 (Mar. 8, 2004).
[70] ATM Initial Brief at 17 (Mar. 8, 2004).
[71] Dallas Initial Brief at 13 (Mar. 8, 2004).
[72] Dallas Initial Brief at 14 (Mar. 8, 2004).
[73] Dallas Initial Brief at 14 (March 8, 2004).
[74] Dallas Initial Brief at 14 (Mar. 8, 2004).
[75] TXU Initial Brief at 6-7 (Mar. 8, 2004).
[76] TXU Initial Brief at 7-8 (March 8, 2004).
[77] TXU Reply Brief at 5 (Mar. 17, 2004).
[78] TXU Reply Brief at 5 (Mar. 17, 2004).

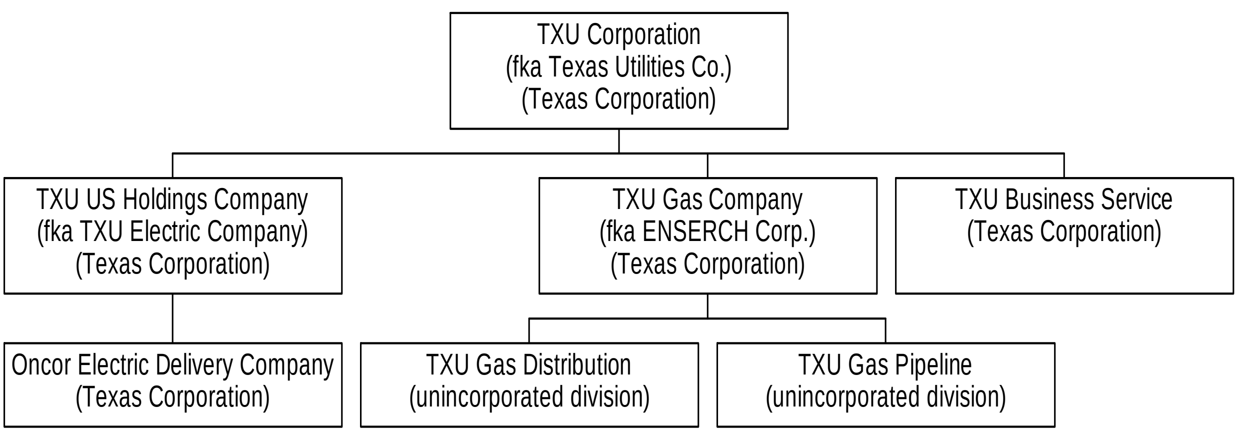
The Commission is vested with the authority and power to ensure compliance with the obligations of the Texas Utilities Code, and with the authority to establish and regulate rates of gas utilities.[79] A gas utility is a virtual monopoly. The property of the business used in this state is subject to the jurisdiction, control, and regulation of the Railroad Commission.[80]

IV. OVERVIEW OF TXU

A. Corporate Structure

TXU Gas Company has initiated this rate proceeding. TXU Gas is a wholly owned subsidiary of TXU Corp. Prior to an August 1997 merger into TXU Corp., TXU Gas was known as ENSERCH Corp. and was an independent, publicly traded company. TXU Corp. is a publicly traded utility holding company and diversified energy company. TXU Corp. engages in numerous businesses such as electricity generation, wholesale energy sales, retail energy sales and related services, portfolio management, energy delivery, and telecommunications services. TXU Corp. discontinued its electric and gas operations in the United Kingdom and Europe in 2002, and now most of its business operations are in the United States and Australia.[81]

TXU Corp. has a number of additional wholly-owned subsidiaries besides TXU Gas which are not part of this proceeding (e.g., TXU Business Services Company, TXU US Holdings Company, TXU Energy Retail Company LP, and Oncor Electric Delivery Company). Within TXU Corp.'s system of companies, TXU Gas is part of the Oncor Group for organizational and management purposes. The Oncor Group also includes Oncor Electric, an electric utility that provides transmission and distribution service in Texas. TXU Gas and Oncor Electric have common management.[82] The following organizational chart illustrates the relationship of TXU Gas within TXU Corp.



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[79] TUC §104.001 (Vernon 1998 and Supp. 2004).
[80] TUC §§101.002 (Vernon 1998 and Supp. 2004), 104.001 (Vernon 1998 and Supp. 2004), and 121.051 (Vernon 1998).
[81] TXU Exhibit 11 at 14-15; TXU Exhibit 12 at 2-11, and TXU Exhibit 22 at 9-11.
[82] TXU Exhibit 11 at 14-15; TXU Exhibit 12 at 2-11, and TXU Exhibit 22 at 9-11.

B. System Description

TXU Gas, which initiated this rate proceeding, is engaged primarily in the transmission and distribution of natural gas in Texas. TXU Gas provides local gas distribution sales service to residential, commercial, and industrial customers and transportation service to industrial customers in North Texas and parts of East, Central, and West Texas. As part of its pipeline operations, TXU Gas provides gas transportation service to the Distribution system and other local distribution companies for further sale and delivery to industrial, commercial, and residential customers behind the city gate, and transportation service for on- and off-system customers in Texas.[83]

TXU Gas further divides its operations into TXU Gas Distribution and TXU Gas Pipeline, neither of which are individually incorporated entities. TXU Gas, through both TXU Gas Distribution and TXU Gas Pipeline, provides service throughout the State of Texas. TXU Gas Pipeline's operations consist of approximately 6,800 miles of transmission and gathering pipelines, five underground storage facilities, and twelve compressor station sites. The pipeline system has connections to the major gas hubs at Waha in West Texas, Katy in South Texas, and Carthage in East Texas. TXU Gas Pipeline transports natural gas to local distribution companies - including TXU Gas Distribution, industrial customers, and other customers for on and off-system usage. TXU Gas Distribution provides natural gas to over 1.4 million customers in 550 Texas communities over some 26,000 miles of distribution mains. TXU Gas Distribution has more than 34,000 miles of high, intermediate, and low pressure mains and service lines that it uses to distribute natural gas.[84]

V. MULTI-AREA ISSUES

The Examiners found that there were three issues that were applicable to several different areas of consideration. Therefore, as a matter of convenience, the Examiners addressed Poly 1 Pipe (Safety Compliance Program), WINS, and Affiliate Transactions as separate issues. Throughout the Proposal for Decision, references are made back to these three topics.

A. Poly 1 Pipe/ Safety Compliance Program

Overview of the Poly 1 Pipe Issue

In 1970 and 1971, the ENSERCH Corporation (ENSERCH), the parent company to Lone Star Gas (Lone Star), installed unknown quantities of first generation polyethylene pipe, also known as Poly 1 pipe.[85] TXU merged with ENSERCH in 1997.[86] The TR-414 resin used to manufacture the Poly 1 pipe was made by Phillips Chemical Company (Phillips). Nipak, Inc.(Nipak), a subsidiary of ENSERCH, used Phillips' TR-414 resin to manufacture the Poly 1 pipe, gave the pipe the material code designation PE 3306, and sold

[83] TXU Exhibit 11 at 14-15; TXU Exhibit 12 at 2-11, and TXU Exhibit 22 at 9-11.

[84] TXU Exhibit 11 at 14-15; TXU Exhibit 12 at 2-11, and TXU Exhibit 22 at 9-11.

[85] TXU Exhibit 13 at 14; ACC Exhibit 4B at 48.

[86] GUD 8976, *Statement of Intent to Change the City-Gate Rate of TXU Lone Star Pipeline, Formerly known as Lone Star Pipeline Company Established in GUD No. 8664,* Final Order at 3 of 23, paragraph 22 (June 22, 2000).

the Poly 1 pipe to its affiliate, Lone Star.[87] Nipak did not sell the Poly 1 pipe to any other gas company.[88] Before Nipak began manufacturing the Poly 1 pipe, Phillips informed Nipak that the TR-414 resin was never intended to be used for the manufacture of gas utility pipe and that the pipe was designed for use in conduit manufacture.[89] There was no Poly 1 pipe in TXU's pipeline system; Poly 1 pipe existed solely in what is currently TXU's Distribution system.[90]

Almost immediately, as early as 1971, the problems with the pipe become known.[91] A summary of the explosions, fires, and consequences attributable to the Poly 1 pipe defects is provided in the chart, below. The problems with the Poly 1 pipe were so significant that Mr. Louis B. Huley of Lone Star ordered that the pipe had to be removed from the warehouse.[92] Over the last thirty years, Lone Star initiated removal programs several times[93] and in 1997, after the Commission's Pipeline Safety Staff became involved, TXU initiated its Safety Compliance Program to replace the pipe.[94] Despite the problems, the replacement program was not completed until after the Garland explosion and the Commission issued its consent orders.[95]

In 2001, the Commission determined that any recovery of the costs by TXU associated with the recovery, removal, and replacement of Poly 1 pipe would be addressed in a future rate proceeding.[96] Starting in January 2003, TXU began filing a series of cases referred to as the Region-wide cases. Before TXU filed its Region-wide statements of Intent with the Commission, the utility had already received approval from the cities for the corresponding rates. As indicated on Schedule B in each of TXU's Region-wide applications, TXU requested and the Commission approved for inclusion in TXU's rate base, the following amounts listed as "Regulatory Asset -- Poly 1 Safety Compliance Program."[97]

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[87] ACC Exhibit 4B at 48.
[88] ACC Exhibit 4B at 48.
[89] ATM 56 (January 15, 1970 letter from G.M. Covington to W.C. McCord at 2 of 5).
[90] ATM Initial Brief at 15.
[91] ACC Exhibit 4B at 48; ACC Exhibit 57 at 4 and 42; Staff Exhibits 4-8.
[92] Staff Exhibit 6.
[93] Dallas Initial Brief at 8 (Mar. 8, 2004); TXU Exhibit 60 at 109. ATM Initial Brief at 40; TXU Exhibit 60 at 120 and 127; TXU Exhibit 60 at 136.
[94] ACC Exhibit 4 at 48 and ACC Exhibit 21 (GUD 9151, Commission Consent Order dated May 23, 2000).
[95] Dallas Initial Brief at 8 (Mar. 8, 2004); ACC Exhibit 21.
[96] ACC Exhibit 21 (GUD 9217, Commission Consent Order dated Dec. 20, 2002 at 3, Stipulation Paragraph 18).
[97] Hearing Examiners' Exhibit 1.

Summary of Amounts of Safety Compliance Program Costs Previously Approved by the Commission for Inclusion in TXU's Rate Base

DOCKET	AMOUNT
GUD 9353, *TXU Gas Distribution Statement of Intent to Change Rates in the Environs of the Cities in the Hill Country Distribution System*	$506,808
GUD 9361, *TXU Gas Distribution Statement of Intent to Change Rates in the Environs of the Cities in the East Region Distribution System*	$1,717,765
GUD 9365, *TXU Gas Distribution Statement of Intent to Change Rates in the Environs of the Cities in the Dallas Region Distribution System*	$2,620,568
GUD 9366, *TXU Gas Distribution Statement of Intent to Change Rates in the Environs of the Cities in the West Region Distribution System*	$3,964,209
GUD 9370, *TXU Gas Distribution Statement of Intent to Change Rates in the Environs of the Cities in the South Region Distribution System*	$2,780,920
GUD 9376, *TXU Gas Distribution Statement of Intent to Change Rates in the Environs of the Cities in the Northwest Region Distribution System*	$1,366,138
GUD 9377, *TXU Gas Distribution Statement of Intent to Change Rates in the Environs of the Cities in the North Texas Metroplex Distribution System*	$14,119,117
GUD 9379, *TXU Gas Distribution Statement of Intent to Change Rates in the Environs of the Longview Distribution System*	$0
TOTAL:	$27,075,525

Although the Commission previously approved these amounts for inclusion in invested capital, this is the first time the issue of recovery of the costs by TXU associated with the location, removal, and replacement of Poly 1 pipe has been litigated. At the time of the eight region-wide rate cases, TXU did not bring to the Commission's attention its inclusion of these amounts in invested capital for its Safety Compliance Program. In GUD 9400, TXU requested the Commission approve a rate of return on the $42,982,796 regulatory asset for test holes dug where no Poly 1 pipe was located.

The issues of whether the Commission should approve the return is ripe for decision in GUD 9400. The issue of whether to include $42,982,796 for the Safety Compliance Program and $87,837,108.64 for utility plant-in-service are also ripe for Commission decision in this GUD 9400 proceeding. Including these amounts in rate base would allow for TXU to earn a return on amounts invested to fund the Poly 1 pipe program (SCP). In this rate making proceeding, the Commission decision in GUD 9400 will consider whether TXU will recover costs relating to the location and replacement of Poly 1 pipe; associated costs such as software expenses, depreciation or amortization of asset and software expenses; legal and litigation fees; and TXU's requested return and associated taxes on the assets.

Expense Accounting

TXU used two categories to classify the costs it incurred in locating and replacing Poly 1 pipe: (1) costs capitalized to gas utility plant-in-service and (2) the Safety Compliance Program (SCP) costs booked as a regulatory asset. From 1997 until December 2000, the utility recorded the costs as construction work in progress.[98] In December 2000, the utility began to record the costs as a regulatory asset.[99] From 1997 until

98 Tr. Vol. 5 at 21 (Jan. 30, 2004).

99 ATM Exhibit 37; Tr. Vol. 5 at 21 (Jan. 30, 2004); Tr. Vol. 3 at 91-22 (Jan. 28, 2004).

2002, TXU incurred Poly 1 pipe costs approximating $133,135,158.14.[100] This amount includes $87,837,108.64 for the removal and replacement of Poly 1 pipe booked as gas utility plant in service and $45,298,049.50 for Safety Compliance Program Costs.[101] The $87,837,108.64 is calculated as follows: $1,835,000.00 (1997) + $10,159,000.00 (1998) + $3,801,259.33 (1999) + $10,656,074.29 (2000) + $59,454,085.30 (2001) + $ 1,931,689.72 (2002) = $87,837,108.64. The $45,298,049.50 is calculated as follows: $22,602,053.73 (2000) + $16,491,383.69 (2001) + $6,204,612.08 (2002) = $45,298,049.50.[102] TXU's proposal in GUD 9400 would result in all of these costs being borne by ratepayers.[103]

Costs Capitalized to Gas Utility Plant-in-Service:
If TXU located Poly 1 pipe through the process of digging a test hole, the Poly 1 pipe was replaced.[104] TXU accounted for the costs of the these test holes and audits by creating a separate replacement project account to accumulate the costs that were being incurred. TXU booked the test hole costs, replacement pipe costs, and other associated costs on the utility's books and records. Upon completion of the project to replace Poly 1 pipe, TXU considered the replaced pipe plant to be "in service" and capitalized the account.[105] From 1997 to 2002, TXU has capitalized to the gas utility plant in service account approximately $87,837,108.64.[106]

Safety Compliance Program (SCP):
If TXU dug a test hole but located no Poly 1 pipe, then TXU recorded the costs as a regulatory asset called the Safety Compliance Program and deferred those test holes costs.[107] TXU expended $45,298,049.50 for its Safety Compliance Program.[108] TXU has previously amortized $2,147,776 and, therefore, proposed the Commission approve reimbursement of $42,982,796 as a regulatory asset[109] and amortized the costs at $3,008,705 annually for fifteen years. (Calculation: $45,130,572 ÷ 15 years = $3,008,704.80 per year, or rounded = $3,008,705.)[110] In the alternative, TXU argued that an alternative amortization period would be the Distribution plant life, or forty years.

Explosions Due to Poly 1 Pipe Defects
A number of pipeline accidents investigated by the National Transportation Safety Board (NTSB) involved plastic piping that cracked in a brittle-like manner.[111] Due to the defects in the brittle Poly 1 pipe, several explosions and fires occurred. A summary of the explosions, fires, and consequences attributable to the

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[100] ATM Exhibit 1at 16-21; ATM Exhibit 1 at 60, line 7 (MLA-3); ATM Exhibit 37; ATM Initial Brief at 41 (Mar. 8, 2004); Staff's Initial Brief at 3 (Mar. 8, 2004).
[101] *See* ATM Exhibit 1 at 59; *see also* ATM Exhibit 37.
[102] *See* ATM Exhibit 1 at 59; *see also* ATM Exhibit 37.
[103] Dallas Initial Brief at 19 (Mar. 8, 2004).
[104] TXU Exhibit 13 at 14.
[105] TXU Exhibit 14 at 19; TXU Exhibit 18 at 24.
[106] ATM Exhibit 1at 16-21; ATM Exhibit 1 at 60, line 7 (MLA-3); ATM Exhibit 37; ATM Initial Brief at 41 (Mar. 8, 2004); Staff's Initial Brief at 3 (Mar. 8, 2004).
[107] TXU Exhibit 18 at 24 and ACC Exhibit 1 at 15.
[108] *See* ATM Exhibit 37.
[109] TXU Exhibit 61 (Feb. 6, 2004 Errata Filing) at Schedules D-4(D) and E-6(D), column (f). See also, Dallas Initial Brief at 8 and at footnote 14 (Mar. 8, 2004).
[110] TXU Exhibit 61 (Feb. 6 2004 Errata filing) at WP/D-4/2(D) and WP/D-4/4(D); TXU Exhibit 14 at 19; TXU Exhibit 18 at 24-25.
[111] ACC Exhibit 4B at 48 citing to NTSB Special Investigation, *Brittle Like cracking in Plastic Pipe for Gas Service* (Apr. 23, 1998).

Poly 1 pipe defects is provided in the chart, below.[112]

Summary of Explosions, Fires, and Consequences Attributable to Poly 1 Pipe Defects

DATE, LOCATION, & COMMISSION REPORT NO.	SUMMARY	CONSEQUENCES
10/04/1971; Fort Worth	Explosion due to leaks in service lines to a plastic main; vertical loading over the connection generated long-term stress that led to the crack	No deaths; one person burned; house exploded
09/01/1978; Fort Worth; 79-09-002	Explosion and fire due to leak on Poly 1 main	No deaths; hospitalization of Hygrade employee and destruction of a supply shed
12/09/1983; Terrell 84-AI-010	Explosion and fire at residence due to leak from gas main at street curb and underground gas migration	1 death 1 treated for minor injuries and released
10/24/1992; Arlington 93-AI-007	Fire resulting from a crack under a support clamp on a main	one injury
12/03/1996; Grand Prairie 97-AI-020	Explosion and fire destroying house, contents, and damaging adjacent homes; no one in the house at the time	7 injured and treated for minor injuries
08/11/1997; Lake Dallas 97-AI-055	Explosion and fire	1 fatality
01/14/2000; Garland 00-AI-013	Explosion and fire at house; gas concentrations in vicinity due to crack in the area of a butt fusion on the main supplying the residence	3 fatalities
10/29/2000; Little Elm 01-AI-011	Explosion at residence due to leak on service tap branch ; accumulation of natural gas migrated from the leaking saddle branch	1 injury

In 1996, after the explosion in Grand Prairie, the Commission's Pipeline Safety Staff met with ENSERCH (Lone Star) regarding the Poly 1 pipe.[113] Thereafter, TXU merged with ENSERCH on August 5, 1997.[114] When TXU merged with ENSERCH, TXU inherited and assumed all responsibilities and liabilities for the predecessor company. It was TXU's responsibility and duty to research ENSERCH's past practices and procedures with due diligence. In 1997, TXU developed a Safety Compliance Program (SCP) to

[112] ACC Exhibit 51; ATM Exhibit 52; TXU Reply Brief at 25-26 (Mar. 17, 2004); ACC Exhibit 4 at 49; ACC Exhibit 4, attachment KJN-9; ACC Exhibit 4 at 49, foot note 109 *citing* to NTSB *Pipeline Accident Report, Lone Star Gas Company, Fort Worth Texas, Oct. 4, 1971* (NTSB/PAR-72/5), referenced in *NTSB Special Investigation, Brittle like Cracking in Plastic Pipe for Gas Service*, Apr. 23, 1998.

[113] ACC Exhibit 4 at 49.

[114] GUD 8976, *Statement of Intent to Change the City-Gate Rate of TXU Lone Star Pipeline, Formerly known as Lone Star Pipeline Company Established in GUD No. 8664,* Final Order at 3 of 23, paragraph 22 (June 22, 2000).

replace the Poly 1 pipe by no later than June 30, 2002.[115] In response to the natural gas explosion in Garland that resulted in three fatalities, TXU accelerated removal of the Poly 1 pipe to June 30, 2001.[116]

In response to the Garland incident, the Commission initiated an enforcement action requiring TXU to survey and replace its Poly 1 pipe by no later than December 31, 2000.[117] But TXU did not meet the deadline imposed by the Commission. TXU requested the Commission extend the completion schedule. The Commission granted TXU an extension of time to survey and replace Poly 1 pipe and associated service lines by April 30, 2001, and non-associated service lines by December 31, 2001. In addition, the Commission assessed a $25,000 penalty for failing to meet the deadline.[118]

TXU, however, failed to meet these extended deadlines. The Commission initiated another enforcement action when Poly 1 pipe was discovered by TXU after May 1, 2001.[119] The Commission assessed an administrative penalty of $225,000 and ordered TXU to meet monthly with Commission staff to report on TXU's audit of the Poly 1 pipe replacement program and to immediately remove any Poly 1 pipe found.[120]

TXU's Failure to Participate in Timely, Meaningful Discovery

In response to ACC RFI-42,[121] TXU responded that TXU Gas installed Poly 1 pipe in its system in 1970 and 1971, but that it did not have data reflecting the amount of Poly 1 pipe installed. In response to ACC RFI-42,[122] TXU claimed that it was in 1997 that the utility determined that it would have to replace all known Poly 1 pipe in its system. ACC's RFI 14-14 referred TXU to its responses to ACC 7-47 and asked the utility if it is " . . . TXU's position that prior to 1997, Nipak never communicated to Lone Star Gas any concern over possible defects in the Poly 1 pipe provided to Lone Star? If such communication did occur, provide a copy of the communication. If documentation is no longer available, provide a statement describing the communication in as much detail as possible, including date or approximate date of the communication, author, recipient, contents, and any response by Lone Star Gas." TXU's response was "Yes." TXU's "yes" was the utility's full response to ACC RFI 14-14.

ACC served RFI 19-08[123] on TXU and asked TXU to "[p]rovide all documents related to Poly 1 pipe in TXU's possession prior to 1997." Attorneys for TXU and ACC discussed this request and came to an agreement.[124] Per that agreement, TXU produced on December 16, 2003, memos and correspondence dated 1970-1989 relating to Poly 1 pipe. That response of approximately 161 pages now comprises ACC Exhibit 81.

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[115] ACC Exhibit 4 at 48; ACC Exhibit 21 (GUD 9151, Commission Consent Order dated May 23, 2000).

[116] ACC Exhibit 4 at 48; ACC Exhibit 21 (GUD 9151, Commission Consent Order dated May 23, 2000).

[117] ACC Exhibit 21 (GUD 9151, Commission Consent Order dated May 23, 2000).

[118] ACC Exhibit 21 (GUD 9186, Commission Consent Order dated Dec. 20, 2000).

[119] ACC Exhibit 4B at 51.

[120] ACC Exhibit 21 (GUD 9217, Commission Consent Order dated Dec. 20, 2001).

[121] ACC Exhibit 81.

[122] ACC Exhibit 81.

[123] *See* ACC RFI 19-08 as part of ACC Exhibit 81 and at ACC Exhibit 52.

[124] Allied Coalition of Cities' Response to TXU's Emergency Motion for Reconsideration of Examiners' Order Striking the Testimony of TXU Witness Duvall (ACC's Response) at 4-5 (Feb. 19, 2004) and at Affidavit of Georgia N. Crump (Feb. 18, 2004) attached to ACC's Response.

On Saturday, February 7, 2004, two weeks after the hearing on the merits began in GUD 9400, TXU produced a box of documents. The documents have been admitted into evidence as ACC Exhibits 102 and 102-B (known as "the Box"). ACC Exhibit 102C is an index to the documents contained in the Box. The intervening parties were unfairly prejudiced because they were deprived of timely, pre-trial access to documents in TXU's custody, control, or possession that were favorable to the Intervening parties' positions and are against the interests of TXU. The evidence in the Box contradicted TXU's previous responses to discovery, indicated Lone Star was aware of potential problems with the Poly 1 pipe much earlier than 1997, showed that Nipak was told that the resin was improper for manufacturing of gas pipe, and provided some amounts of installation of Poly 1 pipe. For the first time, the Intervening parties were made aware of the existence of documentation relating to Poly 1 pipe. The Intervening parties were provided documents relating to historical information regarding defects, various communications relating to Poly 1 pipe, the utility's knowledge regarding the defects, and the intentions of and actions taken by Lone Star to initiate pipe removal programs. For its failure to participate in meaningful discovery, the Examiners' sanctioned TXU by striking testimony of a TXU rebuttal witness.[125]

TXU's Position

It is TXU's position that because it was ordered by the Commission to remove and replace the Poly 1 pipe, the utility should be reimbursed for its costs.[126] TXU stated that because the costs to locate and replace the Poly 1 pipe were borne by shareholders, TXU should be granted a return on that investment. It is also TXU's position that because the Commission ordered it to locate and replace the pipe, its expenditures were reasonable and prudent.

To locate and replace all Poly 1 pipe, TXU reviewed numerous map sheets and dug over 100,000 test holes to locate Poly 1 pipe.[127] TXU argued that all of the costs associated with the replacement program, including the costs of digging the test holes, were reasonable and necessary to comply with the Commission's mandate to remove all Poly 1 pipe.[128] TXU argued that because the Commission gave TXU seven months to complete its removal program, it had an expedited time frame, which caused TXU to incur expenses above and beyond the normal level of expense that would have been incurred if the utility had been able to proceed on its own schedule.[129] TXU stated that for reasons beyond the utility's control, such as weather conditions and labor availability, it was unable to meet the Commission's deadline.[130] Therefore, the Commission extended the deadlines.[131]

TXU argued that its treatment of the unamortized balance of the Safety Compliance Program as a regulatory asset was proper because the costs that were incurred meet the definition of a regulatory asset.[132] TXU stated that the Commission's order to the utility to replace all Poly 1 pipe and its discussions with Commission Staff regarding the program allowed TXU to assume that costs would probably be recovered. The Statement of Financial Accounting Standards (SFAS) 71 provides that a utility may defer the

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[125] Examiners' Letter No. 39 (Mar. 1, 2004).
[126] TXU's Initial Brief at 36 (Mar. 8, 2004).
[127] TXU Exhibit 13 at 14.
[128] TXU Exhibit 13 at 14-15.
[129] TXU Initial Brief at 34 (Mar. 8, 2004).
[130] TXU's Initial Brief at 35 (Mar. 8, 2004).
[131] TXU's Initial Brief at 35 (Mar. 8, 2004); ACC Exhibit 21.
[132] TXU's Initial Brief at 86 (Mar. 8, 2004).

recognition of costs and obligations that, as a result of the ratemaking process, have probable corresponding increases of decreases in future revenues.[133] TXU concluded that it was appropriate to defer recognition of the Safety Compliance Program costs because all that is required is that the recovery be probable; prior approval is not required.[134]

TXU argued that Dallas provided no support for its claim that the pipe was faulty or that the purchase of the pipe from an affiliate was not appropriate.[135] TXU also argued that because investors supplied the funds for the utility's Poly 1 pipe program, investors should be reimbursed for the costs incurred and earn a return on that investment.[136]

In its March 17, 2004, Reply Brief,[137] TXU argued that its decisions regarding Poly 1 pipe were reasonable and prudent at the time the decisions were made. TXU argued the only issue to consider is whether costs incurred in removing Poly 1 pipe were reasonable and necessary. TXU argued that the issue of whether the utility was prudent in installing Poly 1 pipe in 1970 and the issue of whether the Poly 1 pipe was used and useful during the time it remained in serve are not appropriate for consideration because all Poly 1 pipe has been included in rates since 1970 and has been fully depreciated. TXU stated that Poly 1 pipe costs are not included in invested capital in this proceeding.[138]

TXU argued that the standard of review with respect to the removal of Poly 1 pipe must be based on whether the utility's decision were reasonable under the circumstances that were known to the utility at the time decisions were made. TXU argued that because no intervenor has argued the costs of the SCP were unreasonable, the costs must be approved.[139]

TXU argued it was reasonable for the utility to install Poly 1 pipe in 1970. TXU argued the TR 414 resin complied with all federal requirements for polyethylene gas pipe resin.[140] TXU reported that Lone Star tested TR 414 resin.[141] Thus, it was reasonable and prudent for Lone Star to install Poly 1 pipe. TXU noted that the Commission and municipalities approved costs of Poly 1 pipe in invested capital in prior proceedings. TXU pointed to Hearing Examiners' Exhibit 1. TXU argued that none of the NTSB or Commission investigation reports attributed failure to a defect in Poly 1 pipe or TR 414 resin because the reports did not identify the cause of failure or identified the failure as attributable to fittings, fusion and squeezing, or saddle-tap failures.[142]

TXU addressed intervening parties' arguments that Lone Star knew of the faulty pipe in 1971. TXU argued that not until the release of the NTSB SIR in 1998 was there an understanding the Poly 1 pipe was susceptible to brittle-like cracking.[143] TXU noted that the leaks identified in the Leak Survey were

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[133] TXU's Initial Brief at 86 (Mar. 8, 2004).
[134] TXU's Initial Brief at 88 (Mar. 8, 2004);
[135] TXU's Initial Brief at 87(Mar. 8, 2004);
[136] TXU Exhibit 31 at 32.
[137] TXU Reply Brief at 22-37 (Mar. 17, 2004).
[138] Tr. Vol. 3 at 64-66; TXU Reply at 22 (Mar. 17, 2004).
[139] TXU Reply Brief at 23 (Mar. 17, 2004).
[140] 49 CFR §190 (1968) and 49 CFR §192 (1970).
[141] Exhibit 60 at 13 and 69.
[142] TXU Reply Brief at 24-27 (Mar. 17, 2004).
[143] TXU Reply Brief at 27-28 (Mar. 17, 2004).

attributable to construction defects, outside damage, and leaks on steel mains or fittings.[144]

TXU addressed intervening parties' argument that Phillips, the manufacturer of TR 414, warned Nipak that TR 414 resin was unsuitable for gas pipe use. TXU argued that interveners misrepresented the statements contained in ATM Exhibit 56 at 4-8. TXU argued the memo actually represents that Phillips had been marketing TR 414 as a recommended resin for gas utility pipe and fitting use and[145] that the reason Nipak discontinued manufacture of the pipe was not due to perceived problems but because Phillips no longer manufactured TR 414 Resin once TR 418 became available. TXU stated that all plastic pipe of this vintage was first marketed for use in water systems.

TXU repeated its position that the utility's SCP costs are reasonable and prudent and summarized what it characterized as essential facts. TXU argued that NTSB determined in 1998 that it was reasonable for utilities to monitor and replace as necessary first generation polyethylene pipe.[146]

TXU argued that the Poly 1 pipe was used and useful until it was removed from service. TXU stated that intervening parties' arguments to make additional deductions from invested capital ignores that the pipe was used and useful until it was removed from service, and the replacement pipe was used and useful. TXU argued that no municipality challenged the used and useful nature of Poly 1 Pipe in any prior municipal or Commission proceeding.[147]

TXU stated that all Poly 1 pipe located in their system has been removed from invested capital. TXU also stated that all salvage costs of removal replacement was excluded from Poly 1 pipe. TXU argued the removal and replacement of Poly 1 pipe was necessary in the provision of gas utility service. TXU stated there is no basis to reduce TXU's invested capital.[148]

TXU argued that the documents in the Box were non responsive to ACC's RFIs 7-47, 14-14, and 19-8 because the documents are outside of the requested date range, or are not memos or correspondence.[149] TXU argued that ACC RFI 7-42 asked for the number of feet and size of Poly 1 pipe installed but did not ask for the number of feet *in* the system.[150] TXU reported that it does not have documentation of the number of feet installed in the system.

TXU acknowledged its oversight in production of documents relating to Poly 1 pipe, but characterized the results as not severe. TXU argued that it acted in good faith to produce the Poly 1 pipe documents.[151]

ACC's Position

ACC argued that TXU should not recover any money for its Safety Compliance Program because ENSERCH should have removed the faulty pipe in 1971 when there were still records and institutional

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144 TXU Reply Brief at 28 (Mar. 17, 2004); ACC Exhibit 57; ACC Exhibit 58.
145 TXU Reply Brief at 29 (Mar. 17, 2004).
146 TXU Reply Brief at 29-30 (Mar. 17, 2004).
147 TXU Reply Brief at 30-31 (Mar. 17, 2004).
148 TXU Reply Brief at 31-32 (Mar. 17, 2004).
149 TXU Reply Brief at 33 (Mar. 17, 2004).
150 TXU Reply Brief at 34 (Mar. 17, 2004).
151 TXU Reply Brief at 36-37 (Mar. 17, 2004).

knowledge of the location of the pipe. ACC also argued that TXU should not recover for legal expenses that were used to further the delay of removal of the Poly 1 pipe. ACC stated that all costs of replacement for Poly 1 pipe should be removed from TXU's invested capital.[152] As a result, ACC adjusted Distribution depreciation expense by removing TXU's requested amortization for Poly 1 pipe.[153]

In its March 17, 2004, Reply Brief, ACC repeated that TXU should recover no Poly 1 pipe costs.[154] ACC argued that the intervening parties did not learn the history of the utility's use of Poly 1 pipe until eight months after the case was filed and until the evidentiary hearing was halfway through its four-week schedule. ACC argued that the documents in question were responsive to RFIs but were not provided by TXU.[155]

ACC argued that the utility should not be rewarded for manufacturing and installing defective pipe. ACC noted that Nipak manufactured the Poly 1 pipe using resin that the supplier warned was not suitable for use in the manufacture of gas utility pipe.[156] ACC argued that Nipak manufactured the pipe for use in the Lone Star Gas affiliate's distribution system and that this testing resulted in the deaths of at least five people.[157]

ACC argued that even when the utility became aware of the problems by July 1970, the utility continued to install the pipe in its system. The pipe was maintained in inventory until as late as November 1971.[158] ACC argued that the utility's dealings with the Poly 1 pipe resulted in increased expenses to ratepayers over the last thirty years. Now, TXU seeks millions of dollars from customers to correct the defects in the system.[159]

ACC also argued that TXU should not be rewarded for waiting thirty years after the knowledge of the defect of the pipe to remove the pipe from the system. ACC addressed TXU's arguments that it removed the pipe at the direction of the Commission and therefore should recover costs from rate payers. TXU stated that the Commission directed the utility to remove the pipe more quickly than TXU had planned. ACC noted that TXU did not mention its numerous, unsuccessful programs to remove the faulty Poly 1 pipe over the proceeding thirty years. ACC observed that only the threat of enforcement actions and fines provided hefty incentive for the utility to finally complete the removal of the defective pipe from its system.[160]

ACC challenged the credibility of TXU's witness Greer regarding his responses to discovery and his testimony as to when the utility first learned of the Poly 1 pipe defects. In discovery, Mr. Greer informed intervening parties that the utility became aware of the potential Poly 1 pipe problems in 1997. Not until cross examination at the hearing did Mr. Greer respond that "an early indication of potential leaks

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152 Initial Brief of ACC at 12-13 (Mar. 8, 2004).
153 Initial Brief of ACC at 80 (Mar. 8, 2004).
154 ACC Reply Brief at 4 (Mar. 17, 2004).
155 ACC Reply Brief at 4-5 (Mar. 17, 2004).
156 ACC Exhibit 102B at LSG 000355.
157 ACC Reply Brief at 6; ACC Exhibit 58; TR. Vol. 7 at 86-128.
158 Staff Exhibit 6; ACC Reply Brief at 6 (Mar. 17, 2004).
159 ACC Reply Brief at 6 (Mar. 17, 2004).
160 ACC Reply Brief at 7-8 (Mar. 17, 2004).

surrounding the cracking were probably noticed around the mid to late '70s."[161] ACC referenced ACC Exhibit 102, bates number LSG 000279 to support its position that the utility knew as early as July 1970 of the failures with Poly 1 pipe.[162] ACC also noted that Mr. Greer would not agree that the word "failure" could be associated with the Poly 1 pipe until that word was shown to Mr. Greer in document production sponsored by him.[163]

ACC argued that TXU provided no credible evidence to support its claim that the Poly 1 costs were reasonable and necessary. ACC stated that TXU's request to recover costs or investment should be denied due to TXU's deliberate pattern of deception in dealing with municipal and Commission regulators on the Poly 1 pipe issues. ACC stated that TXU has not provided hundreds of pages of documents, and this conduct merits imposition of sanctions in TEX. R. CIV. PRO. §215.2 and §215.3, including the denial of relief and the striking of pleadings, resulting in a complete exclusion of all expenses and investment of Poly 1 pipe.[164] ACC called for denial of attorneys fees related to the three Commission enforcement actions, and removal of replacement costs for the Poly 1 pipe that should have had a 50-year life.[165] ACC argued that ratepayers should not have to provide these funds, and for the long term safety of ratepayers TXU should bear these costs.

ACC argued that TXU cannot rely on the Commission's enforcement orders or prior settled cases as support or prior approval of TXU's Poly 1 pipe costs. ACC argued that the fines were imposed for violations of the Commission's safety standards. ACC stated that TXU cannot rely on the Commission's enforcement order to state the Commission implicitly blessed TXU's cost recovery claim. ACC noted that the Commission's Order in GUD 9217 specifically reserved the cost recovery issue for a future rate case.[166] ACC also disagreed with TXU's position that TXU's Poly 1 pipe removal costs received regulatory approval. At TXU Exhibit 31 at 31 and in its March 8, 2004, Initial Brief at page 88, TXU stated that "[i]n a settled case, the absence of a specific finding disallowing a cost of service item means that the cost is considered to be approved and any shortfall from the requested increase is considered to be a reduction to the return allowed on common equity." ACC argued that settled cases result in no approvals of any items.[167] ACC argued that the U.S. Supreme Court held that cases have no precedential value on issues neither argued nor decided. ACC provided several cases as examples of this premise.[168] ACC therefore concluded that TXU's settled cases in no way set any precedent on the issue of Poly 1 pipe recovery costs.[169]

ATM's Position

ATM argued that the Commission should disallow all Poly 1 pipe costs because:

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161 Tr. Vol. 2 at 68; ACC Reply Brief at 8 (Mar. 17, 2004).

162 ACC Reply Brief at 8 (Mar. 17, 2004).

163 ACC Reply Brief at 9 (Mar. 17, 2004); Tr. Vol. 7 at 110-113.

164 ACC Reply Brief at 10 (Mar. 17, 2004).

165 ATM Initial Brief at 28 (Mar. 8, 2004); ACC Reply Brief at 10 (Mar. 17, 2004).

166 ACC Reply Brief at 11 (Mar. 17, 2004); ACC Exhibit 21, GUD 9217 Consent Order at paragraph 18 (Dec. 20, 2001).

167 ACC Reply Brief at 11 (Mar. 17, 2004).

168 ACC Reply Brief at 12 (Mar. 17, 2004) citing *U.S. v. L.A. Tucker Truck Lines*, 344 U.S. 33, 38 (1952); *Kershaw v. Shalala* 9 F. 3d 11 (5th Cir. 1993); and *Southwestern Bell Tel. Co. v. Public Util. Comm'n of Texas*, 31 S.W. 3d 631 (Tex. App.–Austin 2000).

169 ACC Reply Brief at 12 (Mar. 17, 2004).

- TXU failed to show that costs related to the replacement of Poly 1 pipe were reasonably and prudently incurred;[170]
- It was imprudent of ENSERCH (Lone Star Gas) not to have replaced the pipe earlier, when the cost of replacement would have been less;[171]
- The utility's failure to replace Poly 1 earlier led to deaths and injuries which could have and should have been avoided;[172] and
- When the hearing on the merits began in this GUD 9400 proceeding, ATM was unaware of the extent of Poly 1 pipe failures and the defects, due to a deliberate attempt to keep that information from the parties.[173]

ATM argued that even before Nipak began manufacturing the Poly 1 pipe, Phillips Chemical Company (Phillips) informed Nipak that the TR-414 resin was never intended to be used for the manufacture of gas utility pipe and that it was designed for use in conduit manufacture.[174] ATM argued that Lone Star Gas knew in late 1971 of the defects and hazards of the use of Poly 1 pipe as evidenced by the instructive correspondence regarding the removal and replacement of all Poly 1 pipe.[175] ATM referred to a November 30, 1971, correspondence from Mr. Louis B. Hulsy[176] to support its position. That letter stated that "[y]ou must promptly cause all Nipak polyethylene pipe, tubing, and fittings to be returned to Dallas for full credit. Even more important, <u>we do not want a single foot of Nipak 3306 polyethylene pipe, tubing, or fittings to remain in any Distribution warehouse</u>, either in or out of stock. We must not let a situation exist whereby Nipak 3306 pipe, tubing, or fittings could be inadvertently used in our piping systems." (Emphasis in original.)

ATM argued that Lone Star Gas knew, by December 7, 1972, of fifty-eight "material failures"[177] and by September 7, 1973, Lone Star Gas knew of another seven leaks caused by material failures.[178] "Five of the reported failures were brittle-type longitudinal cracks on various sizes of Nipak PE 3306 pipe . . . all these failures were similar to those previously experienced."[179]

ATM argued that Lone Star Gas knew of the defects and potential hazards of the use of Poly 1 pipe and, therefore, accelerated a leak surveillance program for "Generation I polyethylene pipe."[180] Correspondence dated December 13, 1976,[181] explained that the program was to be "effective immediately." The accelerated leak surveillance program began in 1977.[182] The evidence described that maps marked to show the location of all Poly 1 mains had been distributed in 1972. Priorities for

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170 ATM's Initial Brief 38 (Mar. 8, 2004).
171 ATM's Initial Brief at 26 (Mar. 8, 2004).
172 ATM's Initial Brief at 27 (Mar. 8, 2004).
173 ATM Initial Brief at 41.
174 ATM Exhibit 56 (January 15, 1970 letter from G.M. Covington to W.C. McCord at 2 of 5).
175 ATM's Initial Brief at 28-29 (Mar. 8, 2004); Staff Exhibit 6.
176 Staff Exhibit 6.
177 TXU Exhibit 60 at 74.
178 TXU Exhibit 60 at 85.
179 TXU Exhibit 60 at 85.
180 TXU Exhibit 60 at 109.
181 TXU Exhibit 60 at 109.
182 TXU Exhibit 60 at 109.

replacement were established.[183] Priority One (or Category 1) related to pipes with stress cracking. Priority two (or Category two) related to pipes in congested areas. Priority Three (or Category Thee) related to pipe in non-congested areas.[184] Money was to be budgeted in 1978 to replace Priority One pipe by mid-1979.[185] Replacement of Priority Two pipe was to be completed by mid-1981.[186]

ATM argued that Lone Star Gas knew the defects of Poly 1 pipe, knew Poly 1 pipes had cracks, and knew of the potential hazards, but failed to meet its objectives for pipe replacement by 1979 and 1981.[187] By July 1981, the Lone Star Gas' West Texas Division, had replaced 10,382 feet out of 53,835 feet of Poly 1 pipe.[188] By July 1981, the utility's Fort Worth Division had replaced approximately sixty percent of the Priority 1 pipe; eighty-eight leaks were located involving first generation (Poly 1) pipe during the surveys.[189] By August 1981, the Dallas Division had replaced 227,387 feet but reported that it still had 96,568 feet of Priority 1 and Priority 2 pipe to replace due to stress cracking or Priority 1 location.[190] Greenville reported that it had replaced 41,692 feet but had 39,183 feet still to replace. Greenville noted its special surveys had located 321 leaks on first generation pipe.[191] The East Texas Division had replaced all of its Priority 1 pipe but had not replaced any Priority 2 pipe by August 1981.[192]

ATM noted that in November 1981, Lone Star Gas imposed upon itself a new deadline of May 30, 1982, for replacement of all Priority 1 pipe (pipe with stress cracking) and December 31, 1983, to replace all Priority 2 pipe (pipe in congested areas).[193] However, by 1984, significant amounts of Poly 1 pipe remained in several regions.[194] For example, the Texoma Region reported it had 521,458 feet of Poly 1 pipe (5,639 feet Priority One; 14,125 feet Priority Two; and 501,694 feet Priority Three).[195] The Irving Region reported it had 329,578 feet of Poly 1 pipe (18,606 feet Priority One; 35,394 feet Priority Two; and 275,578 feet Priority Three).[196]

ATM argued that Lone Star Gas knew the Poly 1 pipe was defective because Phillips had warned Lone Star that the Poly 1 pipe was not appropriate for use in gas utility piping;[197] Nipak offered to give credit to Lone Start for all Poly 1 pipe that was returned;[198] and because Lone Star began a program in 1977 to replace all Poly 1 pipe in congested areas.[199]

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[183] TXU Exhibit 60 at 110 and 127.
[184] TXU Exhibit 60 at 110, 127, and 136.
[185] ATM Initial Brief at 32 *citing to* TXU Exhibit 60 at 120 and 127.
[186] ATM Initial Brief at 32 *citing to* TXU Exhibit 60 at 120 and 127.
[187] ATM Initial Brief at 32.
[188] TXU Exhibit 60 at 128.
[189] TXU Exhibit 60 at 129.
[190] TXU Exhibit 60 at 130.
[191] TXU Exhibit 60 at 131.
[192] TXU Exhibit 60 at 135.
[193] TXU Exhibit 60 at 136.
[194] ATM Initial Brief at 33 *citing to* TXU Exhibit 60 at 132-133 and ACC Exhibit 102 ("the Box") at Bates LSG 002139 - 002140 and LSG002147-002149.
[195] ACC Exhibit 102 ("the Box") at Bates LSG 002139 - 002140
[196] ACC Exhibit 102 ("the Box") at Bates LSG 002146 - 002150.
[197] ATM Initial Brief at 39 (Mar. 8, 2004).
[198] Staff Exhibit 6.
[199] TXU Exhibit 60 at 109.

ATM argued that all of this evidence was available to TXU Gas when it merged with ENSERCH on August 5, 1997.[200] TXU stepped into the shoes of Lone Star Gas Company.[201] Lone Star had a claim against Phillips or Nipak to be made whole.[202] ATM argued that ratepayers should not now have to pay the costs that resulted from the purchase and use of a defective product.[203] TXU did not show that Lone Star's purchase of pipe from an affiliate company was prudent, when no bids were solicited and when no action was taken against the affiliate.[204] ATM argued that TXU offered no evidence regarding the failure to replace the Poly 1 pipe at an earlier time, when maps were available to locate the mains.[205]

ATM decided that the utility's attempt to keep information regarding the Poly 1 pipe from the parties was deliberate.[206] TXU redacted LSG Bates Numbers from documents it produced, which became TXU Exhibit 60. Dr. Duvall's notes were not produced until February 9, 2004.[207] The documents listed on Dr. Duvall's notes are referenced by their LSG Bates numbers. ATM argued that TXU had access to this evidence, but failed to produce the documents.

ATM argued that the Commission should disallow all Poly 1 pipe costs because the TR 414 Resin/PE 3306 (Poly 1 pipe) defect was inherent in the manufacture of the pipe; Lone Star and TXU were playing a dangerous game with the lives and property of its customers until all Poly 1 pipe was replaced; the utility knew the pipe was unsafe; and that record evidence indicated the utility knew before 1997 that the pipe must be replaced.[208]

In ATM's March 17, 2003, Reply Brief, ATM argued that TXU made the issue of the prudence and reasonableness of Poly 1 costs much more difficult due to its failure to provide discovery in a timely manner. ACC noted that the discovery that was provided is still incomplete because critical documents are missing from "the Box." ATM stated that even when the 161 pages that comprise TXU Exhibit 60 are added to "the Box," over 300 pages were missing from the Bates stamped pages. ATM questioned the concept that even though PE 3306 pipe (Poly 1 pipe) began to fail almost immediately, TXU did not produce a single document about the TR 414 resin from Phillips or from Nipak or from Lone Star to Phillips. ATM argued that there should have been correspondence produced in discovery that was either to or from Phillips relating to the Poly 1 pipe failures.[209]

ATM argued that TXU's Initial Brief defenses against disallowance of Poly 1 pipe costs is predicated upon misstatements of law and omissions of fact. ATM corrected TXU that it is not Staff and intervening parties which have the burden of proof to show that TXU Gas/Lone Star was imprudent in its decision-making with regard to Poly 1 pipe installation and replacement, but rather it is TXU's burden.[210] ATM stated that the Commission's Rule 7.503 provides that there is a presumption of reasonableness of

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200 ATM Initial Brief at 39 (Mar. 8, 2004).
201 ATM Initial Brief at 39 (Mar. 8, 2004).
202 ATM Initial Brief at 39 (Mar. 8, 2004).
203 ATM Initial Brief at 39 (Mar. 8, 2004).
204 ATM Initial Brief at 39 - 40 (Mar. 8, 2004).
205 ATM Initial Brief at 40 (Mar. 8, 2004); TXU Exhibit 60 at 109-111.
206 ATM Initial Brief at 41-42.
207 *See* Dallas Exhibit 10.
208 Staff Exhibit 6.
209 ATM Reply Brief at 1 (Mar. 17, 2004).
210 ATM Reply Brief at 15–17 (Mar. 17, 2004) citing Coalition of Cities v. PUC, 798 S.W.2d 560 (Tex. 1990).

expenditures if the books and records are kept in accordance with Commission rules, but that the presumption does not exist regarding Poly 1 invested capital.[211]

ATM also asserted that TXU's settlements with cities in 2001 and 2002 do not act to bar the litigation of the prudence of Poly 1 replacement costs or the prudence of Poly 1 replacement costs in this proceeding, as argued by TXU. ATM argued that TXU was unable to support its proposition that in a settlement, a cost of service item is considered approved unless there is a specific finding disallowing the item. ATM distinguished TXU's argument from that position that a settled case could be considered to be *res judicata* of a claim that was or could have been litigated in connection with a settled case. *Res judicata* bars the retrial of claims pertaining to the same cause of action which has been finally adjudicated. To invoke the doctrine, the prior judgment must involve the same issues, subject matter and parties or those in privity. A settled case at the municipal level cannot satisfy these criteria. ATM argued that a municipality's adoption of a rate ordinance is merely undertaking a legislative function but is not adjudicating and is not a final judgment. Therefore, the concept of *res judicata* has no application to ratemaking ordinances and settlements at the municipal level do not qualify for *res judicata* treatment. It is ATM's position that for the purposes of administrative law, the *res judicata* doctrine presupposes a trial has taken place– not a settlement.[212]

ATM went on to argue that a settlement at the Railroad Commission does not invoke the *res judicata* doctrine because there has not been a trial where witnesses have vigorously been cross-examined.[213] The *Coalition of Cities* case made this a requirement before application of *res judicata* principles would be appropriate. All of the same parties participated vigorously in the initial contest with each presenting its own evidence and cross-examining its opponent's witnesses.[214]

ATM argued that the January 10, 2002, Consent Order in GUD 9217, *Enforcement Action Against TXU Gas Distribution for Violation of Commission Statewide Pipeline Safety Rules and Violation of Commission Consent Order in Docket No. 9186*, reserved decision on the recovery of Poly 1 costs to a future rate proceeding. ATM stated that GUD 9217 was decided on December 20, 2001, before any of the 2002 settlements had taken place. Therefore, all those settlements were made subject to the Consent Order which had been agreed to by TXU. ATM argued that this GUD 9400 proceeding, is the first contested rate proceeding which has been litigated after the entry of that Consent Order and therefore GUD 9400 is the future rate proceeding referred to in the Consent Order.[215]

ATM noted that TXU Gas Company was formerly known as ENSERCH Corporation and TXU Gas-Distribution was formerly the Lone Star Gas Company (Lone Star). ATM argued that TXU Gas-Distribution and Lone Star Gas Company are one in the same. The acts of Lone Star Gas Company

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[211] ATM Reply Brief at 15–17 (Mar. 17, 2004).
[212] ATM Reply Brief at 18-20 (Mar. 17, 2004).
[213] *Coalition of Cities v. PUC*, 798 S.W.2d 560 (Tex. 1990).
[214] ATM Reply Brief at 19-20 (Mar. 17, 2004).
[215] ATM Reply Brief at 20-21 (Mar. 17, 2004).

are the acts of TXU Gas Distribution. This is particularly important to understand when evaluating whether the Poly 1 installation or replacement expenditures were prudently incurred.[216]

ATM asserted that TXU failed to prove that the Poly 1 costs were prudently incurred, because the utility could not show prudence of purchasing Poly 1 pipe from a manufacturer who had never before been in that line of business; prudence of purchasing Poly 1 pipe from a manufacturer without taking bids from any other manufacturer; prudence of purchasing pipe from a manufacturer who bought resin from a company which indicated that the resin was not fit for gas pipe; and prudence of failing to replace Poly 1 pipe before 1997 after many years of failures and explosions.[217]

ATM argued that the failure by TXU to meet its burden of proof regarding these issues means that TXU is not entitled to put the requested Poly 1 costs into invested capital. ATM argued that if Lone Star had replaced all the Poly 1 pipe in the 1980s, then the Safety Compliance Program costs and the Poly 1 replacement costs requested in this proceeding would be far less. ATM noted that if Lone Star installed pipe with the TR 418 resin between May and December 1970, then none of the Poly 1 replacement costs would be considered in this proceeding.

Dallas's Position

Dallas argued that it is inequitable to force customers to pay for not only the replacement of plant when the defective Poly 1 pipe was purchased from an affiliate but also the digging of test holes associated with replacement plant.[218] Dallas argued that TXU is attempting to shift the excessive and otherwise non-recoverable costs of the Poly1 pipe program.[219]

Dallas argued that TXU did not meet its burden of proof in this rate proceeding to show the reasonableness of the rates because TXU did not clearly identify the costs. Dallas argued that TXU identified some of the resurvey costs, pipe removal costs, and pipe replacement costs incurred by TXU when Poly 1 pipe was located, but made no effort to take an additional step to identify and justify the prudence or reasonableness of those costs.[220]

Dallas argued that because TXU has not presented sufficient evidence in this proceeding, the Commission can not determine whether costs would have been lower if Lone Star had used the advice of the resin manufacturer that the resin was not intended for gas utility use; if the program had been initiated and completed at an earlier date; or if Lone Star had gotten 700 people from around the country to survey and complete the replacement of mains in the late 1970's or even the early 1980's. Dallas acknowledged that TXU had provided its total spending capitalized to plant in service as $87,837,108.64.[221] Because TXU failed to identify the costs, break out the costs, or justify the costs included in its request for plant in service, Dallas argued TXU has failed to meet its burden of proof on all issues and recommended the

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[216] ATM Reply Brief at 15-16 (Mar. 17, 2004);TXU Exhibit 11, attachment SJH-2:GUD 8976, *Statement of Intent to Change the City-Gate Rate of TXU Lone Star Pipeline, formerly known as Lone Star Pipeline Company established in GUD Docket No. 8664*,(June 26, 2000), Finding of Fact No. 22.

[217] ATM Reply Brief at 22 (Mar. 17, 2004).

[218] Dallas Exhibit 1 at 12.

[219] Dallas Initial Brief at 3-4 (Mar. 8, 2004).

[220] Dallas Initial Brief at 19 (Mar. 8, 2004).

[221] Dallas Initial Brief at 20 (Mar. 8, 2004); ATM Exhibit 37.

Commission (1) exclude TXU's request for a regulatory asset of $42,982,796, (2) exclude TXU's request for return and associated taxes on that asset, (3) exclude TXU's request of $3,008,705 for amortization expense, (4) exclude $212,093 of software and related return and taxes in rate base, (5) exclude $70,698 of amortization expense related to that software, and (6) make an adjustment to TXU's plant in service accounts relating to those replacement costs.[222]

Dallas recommended removal of the amortization expense for the Safety Compliance Program because the costs of the Poly 1 pipe are historic and non-recurring, customers are already paying higher rates due to early replacement of the faulty pipe, the utility's request already includes recovery of the initial cost of pipe that was retired and the cost of the replacement pipe, and because Lone Star and TXU knew of the dangers and ineffectiveness of the pipe before the program was announced and started in 1997.[223]

Dallas argued that TXU did not meet its burden to prove the reasonableness of the costs. Dallas argued that TXU initially expensed the costs and later decided to book the costs as a regulatory asset. However, TXU failed to show the reason for this decision, provided no expert at the hearing on the merits with first hand knowledge of the issues, problems, or reasons for the programs or the change in the method of accounting treatment. TXU Witness Greer had no operational or accounting responsibility for the program. Mr. Watson had no direct responsibility for the program. TXU failed to provide evidence justifying the inclusion of the costs as being reasonable. Therefore, Dallas recommended the Commission reduce Distribution rate base by $43.2 million and Distribution expense by $3.1 million.[224]

Dallas recommended that TXU's request for legal and lawsuit expenses related to the Poly 1 pipe issue be reduced by $104,176 because the expenses were non-recurring and were not justified.[225]

Dallas argued that it is inappropriate for TXU to recover costs to identify and replace faulty pipe that was purchased from an affiliate company. Dallas argued that the reason TXU had not recovered costs of the Poly 1 pipe problems from the pipe manufacturer, Nipak, is because the manufacturer was the affiliate company. Dallas noted that the utility provided no evidence of a bidding process or other evidence to show that an appropriate arm's length affiliate transaction occurred for the initial acquisition of the defective pipe. Dallas also noted that Nipak did not sell its pipe to any other gas company.[226]

In its March 17, 2004, Reply Brief, Dallas argued that TXU presented no witness to specifically sponsor evidence to support the reasonableness of cost of installation or the cost of the replacement of Poly 1 pipe. Dallas stated that no witness explained or testified about the reasonableness of TXU/Lone Star's conduct in not removing this pipe before 1997, or in not removing more of it in the voluntary program in 1997. Instead, TXU referred to its witness Greer to describe the removal program. However, the reasons for the program are never provided. Instead, TXU referenced the Commission's Order to remove the pipe and concluded that the costs were reasonable and necessary.[227]

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[222] Dallas Initial Brief at 19-20 and 33-35 (Mar. 8, 2004) *citing* TUC §104.008 and Dallas Exhibit 1 at 8-13.
[223] Dallas Initial Brief at 33-34 (Mar. 8, 2004); Dallas Exhibit 1 at 8-13.
[224] Dallas Initial Brief at 34-35 (Mar. 8, 2004).
[225] Dallas Initial Brief at 45 (Mar. 8, 2004); Dallas 1 at 44.
[226] Dallas Exhibit 1 at 9-10.
[227] Dallas Reply Brief at 18-19 (Mar. 17, 2004).

Dallas retorted that unsupported conclusions do not rise to the level of evidence.[228] TXU ignored the documentary evidence from its own files that showed problems with this pipe as early as the 1970's, special surveillance programs, and several removal efforts over the years. Dallas argued that the documents show that the pipe should have been removed and replaced long before 1997. It is Dallas's position that Mr. Greer's testimony was not supported and was not connected to the program.[229]

At pages 20 - 21 of its March 17, 2004, Reply Brief, Dallas cited numerous excerpts from the hearing to show that Mr. Greer's blanket statement as to reasonableness is not supported by facts, research, or any expertise in the area of Poly 1 pipe issues. Dallas argued that there is no probative evidence of the reasonableness of the conduct of TXU on the Poly I pipe issue at all. Instead, the problems were well known to TXU/Lonestar prior to 1997, and should have been addressed long before that time.

TXU requested Commission approval for inclusion of costs in invested capital because the removal of the defective pipe that was an improvement in safety; and because investor funds were advanced for this program. Dallas argued that the test hole digging program should have been recorded as an expense item, not capitalized, and not recovered in future years. Dallas argued that the test hole program did not better the plant.[230]

Dallas argued that the utility should not be able to neglect a known problem for years and then when a loss of life occurs (the Garland Explosion), recover extra expenditures to restore safety. Dallas argued that this defies any concept of reasonableness. Dallas argued that TXU provided no evidence to show that the initial purchase and use of this pipe was reasonable or to show that it was reasonable to wait until an explosion resulting in deaths occurred to then rush the SCP program. Dallas concluded that TXU's request for invested capital treatment should be denied as should the amortization of this expense, cost of the replacement pipe, and the software used to track this program.[231]

Railroad Commission Staff's Position

Staff argued that Poly 1 is an ancient problem that should have been corrected long ago. TXU should not be rewarded for its performance and for thirty years of neglect. Staff argued that it is undisputed that explosions, some fatal, were attributable to Poly 1 pipe. Yet, even as late as 1994, the utility was still discussing options other than replacement of the Poly 1 pipe.[232] Staff believed that the utility should have faced its responsibility to its customers over thirty years ago when it discovered the pipe was defective and unsafe. No portion of the cost of Poly 1 pipe should be passed to the ratepayer. Instead, the utility should forego any recovery in this docket related to Poly 1 pipe,[233] should not recover for the Safety Compliance Program;[234] should not be allowed to amortize the costs;[235] and should be prevented from seeking reimbursement of any poly 1 pipe costs in any future capital investment adjustment factor (CIAF) or gas reliability infrastructure project (GRIP), in accordance with TUC §104.301.

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[228] *General Elec. Co. v. Joiner*, 522 U.S. 136, 146 (1977).

[229] Dallas Reply Brief at 18-19 (Mar. 17, 2004).

[230] Dallas Reply Brief at 21.

[231] Dallas Reply Brief at 21-23.

[232] Staff's Initial Brief at 3-4 (Mar. 8, 2004); Staff Exhibit 8.

[233] Staff's Initial Brief at 3-4 (Mar. 8, 2004).

[234] Staff's Initial Brief at 3-4 (Mar. 8, 2004).

[235] Staff's Initial Brief at 3-4 (Mar. 8, 2004).

Examiners' Recommendation

In its December 20, 2001, Consent Order, the Commission determined that any recovery of the costs by TXU associated with the recovery, removal, and replacement of Poly 1 pipe would be addressed in a future rate proceeding.[236] This is the first time this issue has been litigated and is the first opportunity the Commission has been given to examine the expenses incurred in the location, removal, and replacement of Poly 1 pipe. The issues of whether the Commission should approve the requested amounts in rate base and whether TXU should earn a return on those amounts are ripe for Commission determination in GUD 9400.

The Examiners find that if the Commission orders TXU to immediately cease future recovery of all amounts relating to Poly 1 pipe, the utility will have no argument regarding retroactive ratemaking because the Commission is not disrupting any previous rate making decision, but rather is only affecting future rates on a forward basis.

The Examiners find that TXU failed to meet its burden to prove reasonableness and prudence of its expenditures relating to the location and replacement of Poly 1 pipe. The Examiners find that the utility failed to show the reasonableness and prudence of the initial purchase and use of the Poly 1 pipe from its affiliate, Nipak. The burden of proof has two components. First, the utility has the burden of production and is required to bring forward competent evidence as to the reasonableness and necessity of its expenses. By simply opening its books to inspection, a utility enjoys no presumption that the expenditures reflected therein have been prudently incurred.[237] Second, the utility has a burden of persuasion. While there is a presumption that a utility's costs are reasonable and necessary, the utility must still provide evidence that is sufficient on the merits to be persuasive that the expense is prudently incurred. The Examiners find that TXU failed on both production and persuasion to meet its burden of proof.

Because TXU failed to provide sufficient evidence showing that the expenses were prudently incurred, the Examiners find that TXU is not entitled to recover through rates paid by its customers the amounts it expended relating to Poly 1 pipe. Having considered all parties' arguments relating to the Poly 1 pipe, Safety Compliance program issues, the Examiners recommend that with regard to Poly 1 pipe expenses, the Commission:

(1) Order TXU to immediately cease recovery of the $27,075,525 previously approved for inclusion in invested capital relating to Poly 1 pipe or the Safety Compliance Program. The $27,075,525 amount is included in the $42,982,796 included in Schedule E attached to the Order in this proceeding. In TXU's workpapers D(4) 1-2, page 1 line 5 and page 2 line 5, TXU showed its annual amortization expense to be $3,008,705.

(2) Deny TXU's request for a return on any Poly 1 pipe expenses.

(3) Deny TXU's request for $104,176 in legal fees.

(4) Preclude TXU from all future recovery of the expenses capitalized as gas utility plant-in-service.

(5) Preclude TXU from all future recovery of the expenses for its Safety Compliance Program.

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236 ACC Exhibit 21 (GUD 9217, Commission Consent Order dated Dec. 20, 2001 at 3, Stipulation Paragraph 18).

237 *Coalition of Cities for Affordable Utility Rates v. Public Utility Commission of Texas*, 798 S.W.2d 560, 563 (Sept. 12, 1990) Rehearing Overruled (Nov. 28, 1990).

(6) Deny TXU's request to amortize the costs of the Safety Compliance Program over fifteen years, forty years, or over any other time period.

(7) Preclude TXU from any future request for reimbursement of location or replacement of Poly 1 pipe as a Safety Compliance Program or under any other program from the Commission or through capital investment adjustment factor (CIAF) or gas reliability infrastructure project (GRIP), in accordance with TUC §104.301.

(8) Deny TXU's request to have the unamortized amounts of the SCP regulatory asset be included in rate base.

Because the Commission has jurisdiction in this docket over the rates for TXU's entire system, it is appropriate for the Commission to preclude TXU's recovery of the Poly 1 pipe costs from ratepayers located anywhere in the TXU system, either within cities or within the environs.

The Examiners' find that the evidence shows that TXU, or its predecessor Lone Star Pipeline, knew or should have known for the last thirty years of the defects and potential hazards of the Poly 1 pipe. The evidence, i.e., memoranda found in ACC Exhibit 102 "the Box," shows that before the pipe was even manufactured, Phillips told Nipak that the pipe was not intended for use in gas utility service. It is a legitimate inquiry to ask whether TXU's expenditure of money to locate and replace the Poly 1 pipe was reasonable and prudent. The evidence does not show that it was prudent of the gas utility to purchase the Poly 1 pipe from its affiliate, Nipak. The Examiners agree that it was prudent to remove the pipe from service. However, in this case, the inquiry must go further. The Examiners find the evidence to show that the utility's initial use of the Poly 1 pipe in 1970 and 1971 and the subsequent failure of the utility to immediately remove the pipe from service in 1971 was neither reasonable nor prudent.

The Examiners conclude that it was not prudent for the utility to wait until the year 2001 to complete its Poly 1 pipe location and replacement programs. Defects in Poly 1 pipe are attributable to several explosions and fires from 1978 to 2000, resulting in the deaths of five people and injuries to thirteen others. As soon as Lone Star became aware that the pipe was defective in 1971, the utility should have immediately removed and replaced the Poly 1 pipe. This is entirely supported by the great weight of the evidence.

The evidence shows that Lone Star acted imprudently and unreasonably in its initial use of the Poly 1 pipe; Lone Star acted imprudently and unreasonably in its failure to completely remove the defective pipe in 1971; Lone Star acted imprudently and unreasonably in failing to completely remove the pipe from 1971 to 1997; and that TXU acted imprudently and unreasonably in failing to meet both its own internally-imposed and Commission-imposed deadlines to completely remove the pipe from service. The Examiners find no evidence persuasive that the entire costs of the Poly 1 pipe Safety Compliance Program, which result from the imprudent activities of Lone Star Gas in 1970 and 1971, and the imprudent decisions of Lone Star not to remove all Poly 1 pipe in 1971should now be borne by TXU's current ratepayers.

TXU failed to meet its burden to show the reasonableness and prudence of the component expenditures that comprised both the $87,837,108.64 Gas Utility Plant-in-Service or the $45,298,049.50 for its Safety Compliance Program. The Examiners find no evidence regarding the various component expenses that comprise these totals reported by TXU in ATM Exhibit 37. At best, the evidence provided total expenditures for 1997, 1998, and monthly total expenditures for the years 1999 through 2002.[238] The evidence provided by TXU allows the Commission one of two options -- to allow all costs or to disallow all costs. The Examiners do not find record evidence to support any middle ground amount. For example, if the Commission were inclined to allow TXU to recover, through rates, the amounts expended strictly for the physical plant, cost of installation, labor for installation, and initial line testing, it does not have record evidence to support such determination and approval, because TXU failed to include supporting evidence in the record. The Commission could instruct the Examiners to re-open the hearing on such limited issue as the costs of the current plant that is in service. However, allowing the hearing to be reopened at this time would reward the utility for its failure to present adequate information to meet its burden and would reward TXU for failing to participate in meaningful, forthright discovery.

The Examiners find evidence that Lone Star knew of the defect of the Poly 1 pipe and even instructed its employees to remove the pipe from its warehouse and from service. However, the Examiners find no evidence or explanation why Lone Star did not act prudently in 1971 to locate and remove the pipe at that time -- i.e., when the utility first knew of the defect and potential hazards.

The Examiners find no persuasive evidence to determine whether costs of location, removal, and replacement would have been lower if Lone Star had initiated and completed at an earlier date. There exists no evidence in the record to show what the costs would have been if Lone star had acted prudently in 1970 and never used the defective pipe. There exists no evidence in the record to show what the costs of location and removal would have been if Lone Star hd acted prudently in 1971 to locate and remove the pipe. The Examiners do find that if the explosions due to defective Poly 1 pipe, as described in the record evidence, had never occurred, several lives would have been saved and property damage would have been less. Therefore, it would have been prudent to have never used pipe that was not intended for gas utility pipe or to have immediately replaced the pipe in 1971.

The Examiners find no evidence to support the reasonableness or prudence of expenses for legal and litigation fees requested by TXU in the amount of $104,176. Litigation due to imprudent activity is not within the normal practice of a utility. The Examiners find no evidence that those expenses should now be paid by TXU's rate payers.

The Examiners find no evidence to support the reasonableness or prudence of TXU's expenses for software used in the location of Poly 1 pipe nor the associated amortization of software costs. TXU stated that it has no "Poly 1 pipe" software but does have software to track installation, removals, and leak information of all polyethylene pipe in accordance with Commission Rule §7.70.[239] TXU stated that it did not use the software during the SCP. However, TXU failed to show that but for the Poly 1 pipe Safety Compliance Program, it would have needed or used the software. TXU presented no probative evidence as to how the software is used to comply with 16 TEX. ADMIN. CODE §7.70.

When TXU merged with ENSERCH and acquired Lone Star, TXU had an obligation to conduct due diligence as to the business practices of the entity it was acquiring. TXU knew or should have known of the defects of the pipe. It is unreasonable that TXU now requests its rate payers to pay for the location and

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[238] ATM Exhibit 37.

[239] TXU Initial Brief at 38; TXU Exhibit 26 at 6-7; TXU Exhibit 26, attachment JAG-R-1; Tr. Vol. 7 at 173 - 174.

replacement of the defective pipe some thirty years later – especially when the utility was not forthcoming during the discovery process with documents that were clearly against its position.

Because TXU knew of the defects and hazards of the Poly 1 pipe, it should have immediately located, pulled, and replaced the pipe in 1971. In 2002, the Commission determined that any recovery of the costs associated with the recovery, removal, and replacement of Poly 1 pipe would be addressed in a future rate proceeding.[240] The Commission should have never been put in the position of ordering TXU to locate and replace the pipe. Commission Staff became involved after the utility experienced several explosions and fires. The Commission should have never been in the position of having to penalize TXU for its failure to locate and replace the Poly 1 pipe. At the time the Commission stated in its December 20, 2001, consent order in GUD 9217, that it would consider the costs associated with the recovery, removal, and replacement of Poly 1 pipe, the Commission was not aware that Lone Star, and therefore TXU, was aware of the defects and potential hazards of the use of Poly 1 pipe.

TXU's ratepayers should not pay for any portion of the Poly 1 pipe location or replacement. TXU's ratepayers should not pay for litigation costs, legal fees, or lawsuit settlements involving Poly 1 pipe. TXU should be precluded from seeking rate payer reimbursements for any Poly 1 pipe costs from the Commission or through the GRIP process. TXU should be required to reimburse to ratepayers any and all portions previously collected from ratepayers attributable to the location or replacement of Poly 1 pipe.

TXU's argument fails that costs of the Poly 1 pipe or Safety Compliance Program should be paid by customers because it was the Commission that ordered the replacement of the pipe. The defective pipe should have been removed from service long before the Commission ordered TXU to locate and remove all Poly 1 pipe. Documents in existence since 1971 indicated that the utility knew of the potential hazards, knew the need to replace the pipe was urgent, yet failed to meet company deadline after deadline. Not until the Commission ordered the utility to replace the pipe did the replacement program become a serious priority. Even then, TXU failed to meet its deadlines. When the Commission made the decision in 2001 that costs associated with Poly 1 pipe would be addressed in a future rate proceeding, it was not aware of the existence of documents that show that TXU, or its predecessor company ENSERCH, knew or should have known of the defects and potential hazards of use of Poly 1 pipe in the natural gas industry.

During the hearing on the merits, TXU witness Greer was asked whether TXU was still filing monthly updates with the Commission's staff, in accordance with the Commission's Order. Mr. Greer responded that when location of Poly 1 pipe is made, the information is immediately transmitted to the Commission office. This evidence at Transcript Volume 2, pages 156-157 (January 27, 2004), shows that TXU has not yet completed the location and replacement of all of the Poly 1 pipe.

B. WINS

<u>Issue Summary and Overview</u>

In this section regarding WINS, the Examiners distinguish between three areas of TXU's overall structure:

- TXU Corp. is TXU's corporate head;

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[240] ACC Exhibit 21 (GUD 9217, Commission Consent Order dated Dec. 20, 2001 at 3, Stipulation Paragraph 18).

- TXU Business Services is the TXU entity that provides general and administrative services to numerous affiliated entities under the TXU corporate umbrella; and
- TXU Gas is the utility that provides gas services and is the applicant in GUD 9400.

TXU Business Services provides general and administrative services to affiliated companies under the TXU Corporate umbrella, including services to TXU Gas. WINS was TXU Business Services' comprehensive review of TXU's administrative and general (A&G) expenses[241] culminating in a cost savings program initiated in 2002 to identify and reduce operating and capital costs.[242] The program started out as "Worldwide Innovative Services," but as TXU's European operations were discontinued, the name changed to "Winning Innovative Services."[243] TXU Business services conducted the WINS project in three phases (service assessment, core process redesign, and performance management). The recommendations were implemented in the TXU Business subsidiary to benefit all affiliated entities under the TXU Corp. umbrella that receive services from TXU Business Services operations.[244]

TXU proposed to address, through the rates set in GUD 9400, both WINS costs (as an expense) and WINS benefits. TXU proposed to pass to its customers an estimated amount of the net benefit cost savings that are being achieved through the WINS program by reducing the utility's cost of service.[245] At the same time, TXU requested the Commission include an allocated portion of the cost of WINS implementation. The key questions regarding WINS issues were:

- Did TXU Gas meet its burden of proof to show that the costs it incurred for the WINS program were reasonable and necessary?
- Did the TXU Corp. assign to TXU Gas the appropriate amount of WINS savings? If not, what should be the appropriate amount of savings?
- Should the costs of the WINS program be passed through to TXU Gas' customers? If so, how much?

Costs: TXU stated that it incurred one-time costs for implementing of the WINS program, including staff reduction severance and retaining the consulting services of Booze Allen Hamilton.[246] TXU allocated a portion of these program costs to TXU Gas. Therefore, TXU Gas has requested that for setting rates, the Commission approve these costs as an off-set to the savings allocated to TXU Gas. To determine the amount of one-time WINS costs allocated to TXU Gas, TXU added the costs that it allocated to TXU Gas ($1,443,362) to the TXU Gas direct costs ($6,291,595) to calculate the total one-time costs it allocated to TXU Gas ($7,734,957).[247] Of that total, TXU Gas assigned $5,560,483 to Distribution and $2,174,474 to Pipeline ($5,560,483 + $2,174,474 = $7,734,957).[248]

Amortization of Costs: TXU requested the Commission approve WINS one-time costs of $7,734,957, amortized over five years ($7,734,957 ÷ 5 = $1,546,991.40), to be treated as a regulatory asset for inclusion

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[241] TXU Exhibit 18 at 18-21.
[242] TXU's Initial Brief at 77 and 91 (Mar. 8, 2004); TXU Exhibit 18 at 18-21.
[243] Staff's Initial Brief at 4 (Mar. 8, 2004); ACC Exhibit 2 at 41a.
[244] TXU Exhibit 18 at 18-20.
[245] TXU Exhibit 18 at 24.
[246] TXU Exhibit 18 at 18-22; TXU Initial Brief at 78 (Mar. 8, 2004).
[247] TXU Exhibit 18 at 21-22 and Exhibit MDM-2 at 29.
[248] *See* Allocated and Direct Cost assignments for (D) and (P) at Exhibit MDM-2 at 29.

in the rates it charges to its customers. To incorporate this amortization into the rates the Commission approves in GUD 9400, TXU proposed that amount of annual savings approved by the Commission be reduced by the amortized expense, as an offset. Then the approved amortized amount would be deducted to result in a net savings.

Savings: TXU also proposed inclusion of the WINS cost-saving benefits in the rate calculation. TXU identified WINS savings at page 81 of TXU Exhibit 15 (SNR-5). TXU Business Services reported that the WINS initiative should ultimately result in $69 million total savings applicable across the entire TXU corporate structure.[249] During the 2002 test year, TXU identified approximately $27 million of WINS savings**.**[250] TXU estimated the total projected annual reduction in TXU Business Services' general and administrative costs to be $42,224,702, which included beneficial amounts attributable to TXU Gas Distribution of $1,768,158, to TXU Gas Pipeline of $1,198,394, and to Oncor Distribution of $10,392,750.[251] The utility therefore proposed this amount of $42,224,702 as an adjustment to the test year cost of service as a known and measurable adjustment to increase the amount of estimated savings. Intervenors argued that TXU's estimate of savings should be increased.

TXU's Position

TXU argued that the primary objective of WINS was to reduce operating and capital costs from the 2003 levels while maintaining or improving customers' quality of service.[252] TXU argued that its expenditures for implementation of WINS were known, measurable, reasonable, and necessary and should be approved.[253] TXU countered Intervenors' arguments that the utility had understated its savings by arguing that the initial WINS "savings targets" of $303 million were aspirational goals of the savings for a three-year period, while the "estimated savings" of $76.6 million for year 2003 are the actual savings.[254]

TXU argued that TXU Gas customers will benefit from the WINS program through improved service quality, lower costs, reduced revenue requirement, and lower customer rates than would have otherwise been required.[255] Most reductions resulted from reduced staff.[256] TXU argued that it would be one-sided, unreasonable, and unfair to allow gas customers to enjoy the savings benefits without having to pay for the WINS-related program costs.[257] To do so, TXU stated, would discourage utilities from ever undertaking cost reduction programs.[258] TXU recommended customers be allowed to enjoy the costs savings through 2003 and customers be required to pay their share of the costs associated with those savings.[259]

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[249] TXU Initial Brief at 91 (Mar. 8, 2004); TXU Exhibit 31at 14-15.
[250] TXU Exhibit 31 at 15; Dallas Exhibit 1 at 26*;* Dallas Initial Brief at 37 (Mar. 8, 2004).
[251] TXU 18 at 21; TXU Exhibit 15 at 81(SNR-5); TXU Initial Brief at 83 (Mar. 8, 2004).
[252] TXU Initial Brief at 77 (Mar. 8, 2004).
[253] TXU Exhibit 18 at 22.
[254] TXU Initial Brief at 79 (Mar. 8, 2004).
[255] TXU Exhibit 18 at 20.
[256] TXU's Initial Brief at 78 (Mar. 8, 2004); TXU Exhibit 18 at 21.
[257] TXU Initial Brief at 85 (Mar. 8, 2004); TXU Reply Brief at 68 (Mar. 17, 2004).
[258] TXU Initial Brief at 85 (Mar. 8, 2004).
[259] TXU Reply Brief at 69 (Mar. 17, 2004).

TXU argued that it will implement WINS over a three-year period (2003-2005) but requested a five-year recovery period;[260] therefore, the utility stated, its request for an annual costs offset of $1,546,991 to the gas utility's portion of the WINS-related savings is reasonable.[261]

TXU proposed to include in the calculation of rates WINS savings in the amount of $42,224,702. TXU argued this amount is correct because rates are supposed to be set based upon an historic test year adjusted for known and measurable changes. TXU argued that projected costs or savings for two or more years past the test year are not known and measurable and that the possibility that the utility's next rate making may not be for many years does not justify inclusion of the additional savings recommended by the intervening parties. TXU also noted that a rate inquiry can be initiated if, in the future, a city believes the utility is earning more than its authorized rate of return.[262]

TXU argued that it included a WINS adjustment to reflect cost reductions (i.e., savings) in 2003, but included only actual costs incurred in the test year, and no additional costs were incurred in 2003. Arguing against Intervenors' positions, TXU stated that the savings and costs in 2004 or beyond were properly excluded from consideration in this proceeding because the changes are simply not known and measurable.[263]

TXU argued that the purpose of WINS was to decrease administrative and general expenses across all of the TXU businesses, including TXU Gas; therefore, it is irrelevant whether the increases of TXU Corp.'s administrative and general expenses were the catalyst for initiating the WINS program.[264] Because TXU Business Service benefits from the WINS program, it and its client, TXU Gas, should share in the costs.

TXU took issue with ACC's position that TXU Gas customers have been overcharged for services for several years. TXU argued that TXU Business Services has not overcharged TXU Gas for the services it received, as evidenced by Public Utility Commission and Railroad Commission approvals of TXU's previous requests for cost recovery in several cases.[265]

Dallas

Dallas recommended the Commission eliminate TXU's requested WINS one-time costs from rates. Dallas argued that a more realistic level of savings is needed and recommended the rates approved by the Commission reflect increased amounts of WINS-related savings. Dallas stated that elimination of the one-time WINS costs along with a recognition of increased WINS savings has resulted in an overall reduction of Distribution expenses by $4,100,000 and reduction of Pipeline expenses by $1,800,000.[266]

Dallas remarked that TXU failed to clearly present its WINS program. Instead, the utility made approximately 200 boxes of documents available to intervening parties. TXU provided no index to the

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260 TXU Exhibit 18 at 21-23; TXU Initial Brief at 83 (Mar. 8, 2004).
261 TXU Exhibit 18 at 21-23.
262 TXU Reply Brief at 67 (Mar. 17, 2004).
263 TXU Reply Brief at 66 (Mar. 17, 2004).
264 TXU Exhibit 31 at 15.
265 TXU Exhibit 31 at 19.
266 Dallas Exhibit 1 at 5; Dallas Initial Brief at 37 (Mar. 8, 2004).

contents of the boxes and provided no identification of the final program documents.[267] Dallas argued that the utility's organizational presentation of 200 boxes of WINS documents without a usable index showed that TXU failed to support its position and failed to show knowledge of its own cost savings program.[268]

Costs: Dallas's arguments regarding WINS one-time costs are found in Dallas Exhibit 1 at 18-20. Dallas argued that TXU's request for recovery of $7,734,995 ($5,560,000 Distribution + $2,174,000 Pipeline) as WINS one-time costs and TXU's request for total program annual amortization of $1,546,991 ($1,112,097 Distribution + $434,895 Pipeline) for five years, should be denied for two primary reasons.[269] First, TXU has already recovered its WINS costs through the savings it has received since implementing WINS.[270] Second, the WINS program costs are non-recurring and therefore not recoverable.[271] If the Commission were to deny TXU's requested recovery of WINS one-time costs, the result would be a $1,112,097 reduction in expense for Distribution and a $434,895 reduction in annual expenses for Pipeline.[272]

Savings: Dallas's initial arguments regarding WINS savings are found in Dallas Exhibit 1 at 20-28. Dallas argued that TXU's proposal did not adequately share with ratepayers the actual savings experienced through WINS. Dallas argued that the actual savings already enjoyed by TXU are greater than the estimated savings the utility proposed.[273] Dallas reviewed the 200 WINS boxes and located documents indicating savings possibilities ranging from $136 million to $297 million.[274] Dallas concluded that TXU's proposed $42 million savings to be shared with its customers was therefore too low.

Dallas argued that greater levels of WINS-related savings should be passed through to the ratepayer. TXU reported that the total WINS savings for TXU Business Services for the 2002 test year were $42,224,702.[275] Dallas argued the total TXU Business Services' savings should reflect $22,695,000 in addition to the $42,224,702. If the Commission were to agree with Dallas's proposal, the portion of the $22,695,000 attributable to Distribution ($3,079,711) and Pipeline ($1,350,353) would be a total of $4,430,064 additional WINS-related savings to the benefit of TXU Gas' customers.[276]

To make the recommendation in the preceding paragraph, Dallas used an approach different from TXU's to calculate WINS-related savings. Dallas used the estimated level of savings in the last quarter of 2003 ($32,218,000) and derived an annualized savings of $128,872,000 ($32,218,000 X 4 quarters = $128,872,000). The estimated 2004 cost reduction reported by TXU was $144,663,000. Dallas averaged the 2003 estimate of $128,872,000 with the 2004 estimate of $144,663,000 to reach $136,768,000 ($128,872,000 + $144,663,000 = $273,535,000 ÷ 2 = [rounded] $136,768,000). Dallas noted that it did not use the higher 2005 estimated value of $188,365,000 or any other value that exceeded Dallas's calculated 2003 - 2004 average estimated savings. Dallas removed foreign item entries and reduced the

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267 Dallas Initial Brief at 35-36 (Mar. 8, 2004).
268 Dallas Exhibit 1 at 15.
269 Dallas Initial Brief at 35-36 (Mar. 8, 2004).
270 Dallas Exhibit 1 at 22; Dallas Initial Brief at 36-37 (Mar. 8, 2004).
271 Dallas Exhibit 1 at 18-20; Dallas Initial Brief at 35-36 (Mar. 8, 2004).
272 Dallas Exhibit 1 at 20.
273 Dallas Exhibit 1 at 22; Dallas Initial Brief at 36-37 (Mar. 8, 2004).
274 Dallas Exhibit 1 at 23; Dallas Initial Brief at 37 (Mar. 8, 2004).
275 TXU Exhibit 15 at 81 (Exhibit SNR-5).
276 Dallas Exhibit 1 at 25-27; Dallas Initial Brief at 36-37 (Mar. 8, 2004); Dallas Reply Brief at 17.

$136,768,000 average down to $91,695,000, the amount applicable to the North American TXU Business Services' savings.

Dallas used the total test year WINS savings for TXU Business Services ($42,224,702) and added the 2002 test year savings reported by TXU ($27,000,000)[277] to calculate $69,000,000 of TXU's savings. Dallas reduced the $91,695,000 North American TXU Business Services' savings by the $69,000,000 of TXU's savings to determine that the amount of additional savings not already reflected in TXU's $42,224,702 WINS adjustment was $22,695,000 ($91,695,000 - $69,000,000 = $22,695,000). Dallas argued that in addition to the $42,224,702 WINS adjustment, TXU Business Services should realize the benefit of the additional $22,695,000 of WINS savings.[278] The additional $22,695,000 savings attributed to TXU Business Services results in additional WINS-related savings for TXU Gas' customers as a $3,079,711 adjustment to Distribution and a $1,350,353 adjustment to Pipeline.[279]

Dallas compared the WINS program costs and benefits with two previous Commission cases, GUD 8664 and GUD 9145, and concluded that TXU's proposal in GUD 9400 does not adequately attribute the benefits of the WINS savings to customers, thereby benefitting shareholders to the detriment of ratepayers.[280] Dallas argued that because the WINS Program began in 2002 and the resulting savings had already begun to be enjoyed by TXU, the utility already recovered the cost of the WINS program attributed to TXU Gas.[281] To allow the utility another opportunity to recover these amounts through rates would result in a more than double recovery of the same amount.[282]

ACC

ACC contemplated why TXU would initiate a year-long, comprehensive program costing millions of dollars and involving the severance of 1,100 employees, for the purpose of identifying cost reduction opportunities, and then fail to quantify the savings actually identified.[283] ACC had two WINS-related recommendations for the Commission's consideration of the WINS issue: eliminate from rates the costs that TXU incurred to implement WINS and increase the resulting WINS savings that are to be enjoyed by TXU Gas ratepayers.

Costs: ACC argued that with regard to WINS, TXU's expenses were not reasonable and necessary for two primary reasons.[284] First, TXU's administrative and general costs were inflated to benefit TXU's unregulated businesses. ACC questioned whether TXU had included in its requested rates costs that are attributable to TXU's unregulated, competitive businesses.[285] Second, ACC argued that TXU's proposed rates attempt to pass these inflated costs to its gas customers even though its WINS costs would be reduced by the time the new rates are established by the Commission.

[277] Dallas Exhibit 1 at 26; TXU Exhibit 31at 15; Dallas Initial Brief at 37 (Mar. 8, 2004);
[278] Dallas Exhibit 1 at 25-27; Dallas Initial Brief at 36-37 (Mar. 8, 2004).
[279] Dallas Exhibit 1 at 25-27; Dallas Initial Brief at 36-37 (Mar. 8, 2004); Dallas Reply Brief at 17 (Mar. 17, 2004).
[280] Dallas Exhibit 1 at 17; Dallas Initial Brief at 36 (Mar. 8, 2004).
[281] Dallas Exhibit 1 at 18-20; Dallas Initial Brief at 35-36 (Mar. 8, 2004).
[282] Dallas Exhibit 1 at 18.
[283] ACC Exhibit 2 at 50.
[284] Initial Brief of ACC at 4-12 and 103 (Mar. 8, 2004).
[285] Initial Brief of ACC at 4 (Mar. 8, 2004).

ACC argued that TXU failed to meet its burden to establish that its costs are reasonable and necessary. ACC argued that TXU had a $6,000,000 increase in general and administrative expenses in three years (1999-2002) and timed its rate request during this time of increased costs.[286] TXU knew it had an inefficient general and administrative costs service delivery model.[287] Because TXU Business Services' costs were excessive during the test year, TXU's proposed cost of service is excessive; therefore, the proposed amounts cannot be included in rates. ACC argued that TXU failed to explain why TXU Gas shared in the inflated costs or took services from an affiliated company with inflated service costs.

ACC charged that TXU was not forthcoming with material relating to the WINS documents or WINS information. TXU made available in Dallas 177 boxes of poorly organized and poorly indexed documents. Until November 2003 for the entire 177 boxes, TXU provided , a single-page index containing seven, one-line entries.[288] ACC located documents in the 177 boxes that showed the dramatically increased general and administrative costs were not a result of TXU Gas' operations, but rather a result of global business activities.[289]

ACC argued that the increase to TXU's overall general and administrative costs were also due to the utility's involvement in the restructuring of the electrical industry in Texas. TXU Corp.'s 2002 Form10-K, filed with the U.S. Securities and Exchange Commission (SEC), explained that its selling, general, and administrative expenses increased twenty-six percent, to $1.3 billion, and the increase was driven by "higher staffing and other administrative expenses associated with expanded retail sales and wholesale portfolio management operations, as well as higher bad debt expense, all due largely to the opening of the Texas electricity market to competition." The 10-K report went on to indicate that after the completion of the transition to competition (CTC) and TXU's exit of the business in Europe, TXU Corp. initiated cost savings actions in 2002 that continued in 2003.[290]

TXU argued that both the Public Utility Commission and the Railroad Commission have approved TXU's requests for cost recovery relating to the services obtained from TXU Business Services; therefore, TXU argued that ACC is incorrect that customers have been overcharged. ACC responded to TXU's position by arguing that this is the first instance where TXU requested an adjustment relating to WINS, the first time regulators had access to the WINS documents, and the first time regulators have had information showing the excessive cost increases and underlying reasons for those the increases. ACC argued that never before have parties had possession of the statements in the financial reports, starting in late 2002, providing the reasons for and goals of the cost cutting measures.

ACC disputed TXU's position that it is irrelevant why WINS was initiated. ACC argued that TXU failed to explain why TXU Corp. would have TXU Gas share in inflated costs when TXU Gas has captive gas utility customers. ACC argued that TXU Gas customers should not bear costs associated with TXU Corp.'s unregulated business ventures.[291]

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[286] Initial Brief of ACC at 5 (Mar. 8, 2004).
[287] ACC Exhibit 2 at 42 and attachment GWT-30 at 489; ACC Exhibit 73 at 1754; ACC Exhibit 77 at 1676; ACC Initial Brief at 6 (Mar. 8, 2004).
[288] ACC Exhibit 28; ACC Initial Brief at 7 (Mar. 8, 2004).
[289] ACC Exhibit 2 at 42-44 and attachments GWT-31 and GWT-35; ACC Initial Brief at 7 (Mar. 8, 2004).
[290] ACC Exhibit 2 at attachment GWT-33; ACC Initial Brief at 8 (Mar. 8, 2004).
[291] ACC Initial Brief at 8 (Mar. 8, 2004).

ACC argued that TXU's WINS costs will have been significantly reduced by the time new rates are set by the Commission in GUD 9400 because TXU has already implemented costs saving measures and is receiving the benefits of those cost saving measures (i.e., savings) until the Commission's decision in GUD 9400. ACC argued that TXU Corp.'s annual costs will have been reduced by over $120 million by the time the rates approved in GUD 9400 go into effect.[292] ACC argued further that because TXU is currently in the process of implementing additional cost saving measures TXU's shareholders will enjoy the additional savings while the GUD 9400 rates are in effect. ACC concluded that TXU will be able to recover revenues well in excess of its actual expenditures.[293]

ACC argued that the issue is not whether TXU will implement cost reductions or when reductions may occur. TXU may overspend at the expense of shareholders. Rather, the issue is whether TXU's test year costs were reasonable and necessary. It was ACC's contention that TXU did not meet its burden to prove the reasonableness and necessity of the costs; the costs should never have been charged to TXU Gas.[294] ACC recommended that because none of the reasons stated by TXU as to the need to reduce costs related to TXU Gas, none of the WINS costs incurred to achieve the WINS savings should be borne by the TXU Gas ratepayers.[295] ACC recommended the Commission disallow TXU's requested $1,112,096 Distribution and $434,895 Pipeline amortization amounts for WINS one-time costs.

Savings: ACC also recommended that all of the anticipated savings attributable to TXU Business Services be included as a negative adjustment to the test year costs-of-service. Rather than the $42,224,794 savings identified by TXU to be deducted from test year costs, ACC argued that $231,100,000 is a more appropriate number.[296] ACC argued that TXU understated its savings in this proceeding by claiming the "estimated savings" of $76.6 million for year 2003 are the actual savings as opposed to the initial, aspirational WINS "savings targets" of $303 million.[297] ACC took issue with TXU's position[298] that it would be inappropriate to adjust the 2002 test year for targeted savings that may or may not occur in 2004 and 2005. ACC argued that particular WINS documents show that both TXU and its consultant believed that $300 million in cost savings could be achieved.[299]

As examples, ACC directed attention to ACC Exhibit 2, GWT-29 and to ACC Exhibit 2, GWT-30. ACC stated that ACC Exhibit 2, GWT-29 shows TXU's effort to accelerate the pace of the WINS program in order to realize $75 million in 2003 and $300 million long-term. ACC stated that ACC Exhibit 2, GWT-30 shows that TXU Energy (Oncor) experienced a $600 million operating and maintenance cost increase since 1999 due to expansion of wholesale marketing, competition, and the opening of the Texas electricity market.

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[292] ACC Initial Brief at 9-10 (Mar. 8, 2004); ACC Exhibit 48 at 3915.
[293] ACC Initial Brief at 9 (Mar. 8, 2004).
[294] ACC Initial Brief at 10-11 (Mar. 8, 2004).
[295] ACC Exhibit 2 at 50.
[296] ACC Exhibit 2 at 51.
[297] ACC Exhibit 2 at 50; ACC Initial Brief at 8; TXU Initial Brief at 79 (Mar. 8, 2004);
[298] TXU Exhibit 31at 17.
[299] ACC Reply Brief at 3 (Mar. 17, 2004); *See especially* ACC Exhibit 2, GWT-29; ACC Exhibit 2, GWT-30; ACC Exhibit 2, GWT-31; ACC Exhibit 2, GWT-36; ACC Exhibit 2, GWT-37; and ACC Exhibits 42, 48, 73, and 77.

To support its conclusion that $231,100,000 is a more appropriate amount of savings for TXU Gas, ACC based its adjustments on TXU's $300,000,000 company-wide target savings, and calculated that 77.1 percent of the WINS benefits were attributed to TXU Gas Services (benefits to TXU Business Services $187,770,000 ÷ total WINS benefits of $243,526,000 = 77.1 percent).[300] ACC argued that the $300,000,000 targeted savings was indicated throughout the WINS documents.[301] ACC therefore concluded that the portion of the $300,000,000 target that is assigned to TXU Business services is $231,100,000 (71 percent of $300,000,000 = $231,100,000).[302] ACC's calculation resulted in $6,892,675 (Distribution) and $4,394,220 (Pipeline) to add to the TXU Gas utility's calculation for savings. ACC argued that without this adjustment to TXU's 2002 expenses, TXU Gas ratepayers would subsidize TXU Corp.'s unregulated, competitive activities.[303]

ACC challenged TXU's statement (located in TXU Exhibit 18 at 22) that WINS will be fully implemented over a three-year period and that TXU is passing the estimated benefits of WINS to its customers immediately. ACC argued that, in reality, TXU is not passing the benefits (i.e., the reduction of excessive costs identified as part of the WINS program) to its gas customers because most of the reductions needed to bring TXU's costs to a reasonable level were not implemented when TXU prepared its GUD 9400 filing and because the WINS program will not be fully implemented until the end of 2005.[304]

ATM

ATM opposed TXU's proposed inclusion of amortization of the one-time, non-recurring WINS costs. ATM noted that TXU's stockholders will benefit from the $250 million cost savings currently being enjoyed until new rates are established in this proceeding. ATM argued that it would be inconsistent and improper to allow TXU to defer one-time, non-recurring expenses from the WINS program while the related costs savings are already being passed along to its shareholders.[305]

ATM countered TXU's position that WINS payroll reductions should be matched with the costs to achieve those savings by arguing that TXU failed to match costs and benefits. Unlike the one-time implementation and severance costs, the savings are recurring but have not been shared with customers. [306]

ATM challenged TXU's position that the WINS costs are recurring because, ATM argued, WINS is a downsizing program; severance costs are not incurred during the rate year.[307]

Commission Staff

Staff agreed with ACC that none of the WINS costs incurred to achieve the WINS savings should be included in rates.[308] Staff summarized that the allocated savings of approximately $3 million included by TXU represented only savings that were achieved by the end of the first quarter of 2003, which is not

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[300] ACC Exhibit 2 at 50 -51 and attached GWT 37 at 15; ACC Initial Brief at 8 (Mar. 8, 2004).
[301] ACC Exhibit 2 at 50; ACC Initial Brief at 8 (Mar. 8, 2004).
[302] ACC Exhibit 2 at 50; ACC Initial Brief at 8 (Mar. 8, 2004).
[303] ACC Initial Brief at 8-9 (Mar. 8, 2004).
[304] ACC Initial Brief at 9 (Mar. 8, 2004).
[305] ATM Initial Brief at 53 (Mar. 8, 2004).
[306] ATM Reply Brief at 35. (Mar. 17, 2004).
[307] ATM Reply Brief at 35. (Mar. 17, 2004).
[308] Staff Initial Brief at 4 (Mar. 8, 2004).

representative of the savings for a full test year. Staff argued that a more representative savings allocation for TXU Gas for the entire test year should be in the range of $11-12 million, or four times the proposed amount of $3 million included by TXU Gas.

Staff was perplexed by TXU witness Moseley's statement that he was unaware of whether TXU had ever offered services to an entity other than an affiliate of TXU.[309] Staff asserted that the WINS program is an attempt by TXU Corp. to have one of its regulated affiliates, TXU Gas, subsidize the unregulated TXU Business Services so that it will appear that a competitive environment exists.

Examiners' Recommendation

The Examiners make two recommendations regarding WINS. First, the Examiners recommend the Commission deny TXU's request to include WINS costs in the rates for TXU Gas' customers. Second, the Examiners recommend the Commission approve TXU's proposal to include WINS savings in rates; however, the Examiners recommend increasing the amount of WINS savings, consistent with Dallas's recommendation.

As a matter of good public policy and business practice, both regulated and un-regulated businesses should review their practices and procedures, make internal costs evaluations, and implement cost-saving measures. Utilities should review internal practices and staffing levels and implement cost savings plans. However, when a regulated gas utility seeks approval by the Commission of cost recovery for programs such as WINS, the utility should be prepared to meet its burden to prove the reasonableness and necessity for the costs incurred, as required by statute.

The evidence shows that consideration of TXU's reason or reasons for initiation of the WINS program is relevant to the Commission's determination of the reasonableness and necessity for TXU Gas' costs and expenditures. The regulated gas utility should not subsidize another entity; TXU Gas customers should bear neither the costs incurred by another affiliated entity nor the increased costs due to the activities of an affiliated entity under TXU's corporate umbrella. The Examiners find that the evidence does not show that the expenditure of money for reducing costs was a result of increases in TXU Gas' administrative and general costs. Instead, the great weight of record evidence shows that TXU's need to reduce general and administrative expenses was due to the significant increase in those costs resulting from TXU Corp.'s overseas business ventures and its involvement in the restructuring of the electrical industry in Texas.

The Examiners find that TXU failed to meet its burden to show the WINS costs were reasonable and necessary for the provision of gas utility service. The evidence shows that from the beginning of WINS, the utility never intended to track all savings that were accomplished as a result of the WINS effort.[310] Because TXU decided at the initiation of the WINS project not to track the savings, TXU should have planned from the beginning to provide other evidence to meet its burden to prove that the costs of planning and implementing the WINS program were reasonable and necessary. In fact, this very concept was contemplated by TXU when it contemplated treatment of WINS costs. The first paragraph of ACC Exhibit 42 considers that costs assigned to a regulated entity may be subject to rate recovery with proper support

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[309] Staff Initial Brief at 4 (Mar. 8, 2004); Tr. Vol. 5 at 57-58.

[310] TXU Exhibit 31 at 22.

and documentation. The paragraph goes on to state that the decision to defer the costs for recovery is the responsibility of the regulated entity.[311]

TUC §104.055 raises the standard of proof for transactions between affiliated entities. Subsection (b) requires the Commission to make specific findings with respect to each affiliate transaction. First, the Commission must make a specific finding of the reasonableness and necessity of each item or class of items allowed. Second, the Commission must find, specifically, that the price to the gas utility is not higher than the prices charged by the supplying affiliate to its other affiliates or divisions or to a non-affiliated person for the same item or class of items.

The utility's recognition of increased administrative and general costs across the TXU Corp. and TXU's initiative to combat increased costs is not enough evidence to be persuasive that the WINS costs were necessary and reasonable expenses *for TXU Gas*, in light of the great weight of the evidence showing that it was TXU's other business enterprises that caused the significant increase in administrative and general expenses. Those other TXU Corp. entities that caused the increased administrative and general expenses should carry the burden and pay for the WINS costs.

As previously stated, the purpose of this administrative hearing is to put into evidence information that can be used by the Examiners to make recommendations for setting rates and that can be used by the Commission to support its rate determination. The Commission is required to set rates that are just and reasonable and based in part upon expenditures (i.e., the cost-of-service) that are reasonable and necessary. When TXU proposed to include WINS- related costs and savings in its rates, TXU assumed an obligation to put forth competent, comprehensive evidence. The Examiners appreciate that TXU gathered 177 or more boxes of WINS-related materials and documents for consideration in this docket.

However, TXU's failure to present the WINS materials in an organized fashion or to timely provide a usable and meaningful index hampered the utility's ability to provide evidence to meet its burden of proof and handicapped the other parties' ability to consider the WINS issues. TXU failed to present evidence to meet its burden to prove that its expenditures were reasonable and necessary.

TXU argued that Intervenor parties failed to show that TXU Gas was required to share in any increased administrative and general costs. The Examiners did not find the evidence to show that TXU Gas has been charging rates other than those approved. However, TXU is now asking the Commission to allow TXU Gas customers to share in the costs of the WINS program, costs that were incurred due to increased administrative and general costs of the TXU companies affiliated with TXU Gas. The evidence clearly establishes that TXU Corp. experienced significant administrative and general cost increases that were not attributable to its operation as a gas utility or attributable to its service to gas utility customers. The evidence shows that the increased administrative and general costs were due to TXU Corp.'s other business activities, such as increased costs for implementation of the statutorily required restructuring of electric utility operations in Texas and for TXU Corp.'s business ventures overseas in Europe and Australia. The Examiners find the 2002 Form 10-K prepared by TXU and on behalf of TXU to be probative evidence.

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[311] ACC Exhibit 42.

TXU requested that the portion of WINS costs attributable to TXU Gas be incorporated into the rates paid by the utility's gas customers. However, the Examiners find that TXU did not meet its burden to show that the WINS costs were reasonably and necessarily incurred by or on behalf of TXU Gas. The evidence provided by TXU regarding its proposed treatment of WINS costs and WINS savings fails to meet the utility's burden to prove the reasonableness and necessity of the costs. Instead, the great weight of the evidence demonstrates that TXU Corp.'s other business activities caused a dramatic increase in its administrative and general expenses. While it is reasonable and necessary for TXU Gas to pay for the general and administrative services it uses, TXU failed to provide competent and probative evidence to show that it is reasonable for the customers of TXU Gas, a regulated utility, to pay for increased costs due in substantial part to TXU Corp.'s other businesses, both regulated and unregulated.

TXU provided no evidence showing that the need for a cost-efficiency or cost-cutting program was in any part due to the provision of gas utility service. Instead, the evidence shows that administrative and general costs had to be addressed due to TXU Corp.'s overseas business ventures. Therefore, the Examiners find that the evidence does not support TXU's position that TXU Gas should pay a portion of the costs to implements the WINS program. The intervening parties argued that TXU has, since implementation of the WINS program, recovered the amount of costs attributable to TXU Gas. It is not reasonable for TXU to retain the additional savings that have been achieved through WINS. The evidence shows that the amount that TXU proposed to attribute to TXU Gas understates the anticipated and the actual WINS savings. Therefore the Examiners recommend the Commission approve WINS savings at a level higher than that proposed by TXU.

The Examiners also find that the evidence does not support the level of WINS savings proposed by TXU Gas. Dallas's review of the WINS documents revealed savings possibilities ranging from $136 million to $297 million.[312] ACC argued that both TXU and its consultant sought $300 million in cost savings. TXU argued that $300 million was an aspirational savings target goal. The Examiners find the great weight of the evidence supports the Intervenors' position that the amount of WINS savings should be increased. The Examiners recommend the Commission rely upon Dallas's calculation to increase the savings amounts that are to be included in the approved rates. Dallas's recommendation used a conservative method, based on amounts supplied by TXU, to calculate the increased amounts as a known and measurable change. Dallas's recommendation is based upon the annualized fourth quarter savings of 2003, averaged with TXU's estimated savings for 2004. Dallas omitted the higher 2005 estimated numbers from the averaged calculation.

ACC also suggested the WINS savings be increased and provided an alternative means for calculating the increase. ACC suggested that TXU Corp's $300 million anticipated savings is the realistic amount upon which savings should be based. ACC also supported its position by noting that TXU will initiate and implement future savings programs. The Examiners find that ACC's suggestion is too speculative, at this time, to rely upon its recommendation as a known and measurable change.

[312] Dallas Exhibit 1 at 23; Dallas Initial Brief at 37 (Mar. 8, 2004).

C. Affiliate Transactions

TUC §104.055(b) provides the standard for review of transactions between gas utilities and their affiliates. In establishing a gas utility's rates, the regulatory authority may not allow a gas utility's payment to an affiliate for the cost of a service, property, right, or other item or for an interest expense to be included as capital cost or as expense related to gas utility service except to the extent that the regulatory authority finds the payment is reasonable and necessary for each item or class of items as determined by the regulatory authority. That finding must include:(1) a specific finding of the reasonableness and necessity of each item or class of items allowed; and (2) a finding that the price to the gas utility is not higher than the prices charged by the supplying affiliate to its other affiliates or divisions or to a non-affiliated person for the same item or class of items.[313]

TXU argued that the most recent published court opinion to address the affiliate transaction standard applicable to gas utilities is *City of Amarillo v. Railroad Comm'n*, 894 S.W.2d 783 (Tex. App.--Austin 1995, writ denied). The opinion construes former Gas Utilities Regulatory Act §5.06(b) (TEX. REV. CIV. STAT. ANN. ART. 1446e, §5.06(b) (Vernon Supp. 1995), which was re-codified in 1997 as Texas Utilities Code §104.055(b).

In *Amarillo*, the appellate court held that payments to affiliated entities are presumed excluded from rate base (invested capital) or operating expenses unless the utility presents evidence and the Commission finds that each item or class of items is reasonable and necessary and that the price charged is not higher than the charge to other affiliates, divisions, or unaffiliated entities for the same item or class of items.

TXU argued that *Railroad Comm'n v. Rio Grande Valley Gas Co.*, 683 S.W.2d 783 (Tex. App.--Austin 1984, no writ), an opinion cited for its discussion of affiliate transactions, construes a former section of the Public Utility Regulatory Act that is no longer in effect and no longer applies to gas utilities. The most notable difference between the statute construed in *Rio Grande* and the affiliate transaction standard in TUC §104.055 is the absence in §104.055(b) of the requirement in the old Public Utility Regulatory Act that the regulatory authority's finding of reasonableness "include specific statements setting forth the cost to the affiliate of each item or class of items in question." TXU concluded that a proper analysis of affiliate transactions in this proceeding must consider the standard of §104.055(b) as construed by *City of Amarillo*, rather than *Rio Grande*, which contemplated a now-repealed statute.[314]

TXU Gas receives affiliate services from the following entities: TXU Business Services, TXU Energy, Oncor Electric Delivery Company, and Vermont Insurance.

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[313] TUC §104.055(b) (Vernon 1998).
[314] TXU Initial Brief at 100-101 (Mar. 8, 2004).

Summary Table: Affiliate Transactions

TXU Entity Transacting with TXU Gas	**Transaction Description**
TXU Business Services	Administrative Services
TXU Energy	Service Level Agreement (SLA) and Customer Information System (CIS) lease back including billing, payment processing, and customer care services
Oncor Electric Delivery Company	Operations Support including reading customer meters, design and engineering of certain construction projects, certain operating activities, developing and maintaining community and municipal relations, and managing business and economic development programs
Vermont Insurance	Insurance/ Injuries and Damages

1. TXU Business Services

Like TXU Gas, TXU Business Services Company (TXU Business Services), is a wholly-owned subsidiary of TXU Corp. TXU Business Services provides a variety of administrative and other services to TXU Corp. and to several TXU Corp. subsidiaries, including TXU Gas, including accounting, financial, information technology, personnel, procurement, environmental, real estate, corporate secretarial, and facilities management. TXU Gas sought recovery through rates of the costs for services provided by TXU Business Services to both Distribution and Pipeline.[315] TXU reported that the services provided by TXU Business Services are billed to each entity served, in accordance with the cost driver, to each subsidiary "at cost," i.e., with no return or profit added.

The most significant issues pertaining to TXU Business Services expenses included whether the charges were reasonable and necessary for the provision of gas utility service and whether TXU met its burden of proof with respect to these affiliate transactions, in accordance with TUC §104.055.

This Business Services section is divided into two subsections. The first subsection provides a general overview of the parties' positions relating to TXU Business Services. The second subsection summarizes the parties' specific arguments regarding the disputed Activity/Project accounts. The Texas Utilities Code requires the Commission to determine whether TXU met its burden to prove that its costs are reasonable and necessary. Therefore, the second subsection includes examination of each category along with the Examiners' recommendation. Intervening parties presented challenges to approximately 41 of the Activity/Project accounts, recommending either partial or total disallowance.

[315] TXU Exhibit 15, SNR-2 at 15.

Subsection A: Overview of Parties' Arguments Relating to TXU Business Services

Overview of TXU's Arguments Regarding Business Services Issues

TXU argued that the costs for services provided by TXU Business Services to TXU Gas during the test year[316] were reasonable and necessary[317] and the amounts paid by TXU Gas to TXU Business Services during the test year were reasonable and necessary[318] and were no higher than the amounts charged by TXU Business Services to other affiliates or divisions or to a non-affiliated entity for the same item or class of items. TXU argued that the changes to the TXU Business Services charges for the test year ending December 31, 2002, were known and measurable and should be approved by the Commission as adjustments to the utility's proposed cost of service.[319]

TXU stated that no intervening party's witness challenged the reasonableness and necessity of the incremental project expense items as detailed in SNR-2; the billing methodologies used by TXU Business Services to assign costs to TXU Gas; the proper billing or assignment from TXU Business Services; the application of the statutory affiliate transaction standard; or the use of a centralized business services organization. TXU summarized its position by stressing that TXU Business Services provided its services to TXU Gas and to the other TXU Corp. subsidiaries at cost, with no profit. Unlike affiliate transactions where the providing affiliate is earning a profit, TXU argued there is no benefit to TXU Gas or any other TXU Corp. entity to procure more services from TXU Business Services, or to pay a higher price for those services, than is required by that entity in order to conduct its business. TXU concluded that it met its burden of proof under the statutory affiliate transaction standard with regard to the charges by TXU Business Services to TXU Gas and that the Intervenors' proposals to disallow costs should be rejected.[320]

TXU countered Dallas's arguments[321] that TXU Business Services made a profit on the provision of services to TXU Gas and other TXU Corp. entities. TXU explained that interest expense that is a component cost of certain services provided by TXU Business Services to its customers is not a profit to TXU Business Services. While TXU acknowledged that there is interest expense included in TXU Business Services' charges to TXU Gas and other affiliates, the utility argued that it is an expense item or a carrying cost rather than a profit. TXU Business Services incurred interest expense and passed that expense to its customers; to disallow recovery of interest expense would require TXU Business Services to operate at a loss.[322]

In response to Dallas's and ACC's recommended partial or full disallowance of TXU Business Services charges to TXU Gas, TXU made the following arguments:[323]

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[316] On the first line of page 112 of TXU's March 8, 2004, Initial Brief, TXU referred to the test year as ending December 31, 2003. The Examiners will assume a clerical error was made because the test year ended December 31, 2002 and the 2002 test year is correctly reflected at line 10.

[317] TXU Exhibit 15 at 16; TXU Initial Brief at 112 (Mar. 8, 2004).

[318] TXU Exhibit 15 at 14.

[319] TXU Gas Exhibit 15 at 17 and 35; TXU Initial Brief at 112 (Mar. 8, 2004).

[320] TXU Initial Brief at 112 -114 (Mar. 8, 2004); TXU Gas Exhibit 15 at 4.

[321] Dallas Initial Brief at 46 (Mar. 8, 2004).

[322] TXU Gas Exhibit 15 at 4; TXU Reply Brief at 77 (Mar. 17, 2004); Tr. Vol. 4 at 46-51.

[323] TXU Exhibit 15 at 10; TXU Exhibit 28 at 8-10 and 11-52; TXU Reply Brief at 77-80 (Mar. 17, 2004); Tr. Vol. 4 at 52.

- Dallas and ACC used conjecture without supporting evidence. Dallas and ACC reviewed TXU Business Services' test year activities and projects, observed the cost had increased from prior years, and without considering any supporting evidence, concluded the test year costs were too high.
- Dallas relied upon outdated information. Dallas relied upon GUD 9313 with a test year ending September 30, 2001, and upon Public Utility Commission Docket No. 22350 with a test year ending September 30, 1999.
- TXU Properties had negative income in 2002, so it could not have earned a profit during the test year.
- Ad valorem and income taxes are expense items and do not inure to the benefit of TXU Business Services.
- The TXU Business Services model has been approved previously by the Commission and the Public Utility Commission. No credible testimony from a qualified witness was presented to challenge TXU Business Services' incremental expense items in GUD 9400.
- Whether an item is capitalized or expensed is not discretionary but is a function of generally accepted accounting principles (GAAP). Capital expenditures relate to the acquisition of an asset, the benefit of which extends over one or more accounting periods beyond the current period. Pipeline did not capitalize certain expenses because it has not been in an intensive construction mode and the services performed by TXU Business Services have supported operational needs. Distribution capitalized construction-related expenses because they were incurred to support capital construction efforts. Dallas's recommended disallowance and failure to recognize the portion capitalized, understated the amount included in cost of service.
- Nothing in the Utilities Code or Commission regulations prohibits TXU Business Services from earning a profit, so long as the affiliate expenses are reasonable and necessary and otherwise meet the "no higher than" standard set out in the Utilities Code.
- Just because costs increased does not mean they are unreasonable.
- TXU Gas met its burden under the Utilities Code with regard to TXU Business Services expenses.

Overview of Dallas's Arguments Regarding Business Services Issues

Dallas took the position that because expenses for certain TXU Business Services costs were not reasonable or were not representative of the level of expense to be incurred, an overall reduction of $4,262,265 to TXU Business Services was appropriate. Dallas argued that if a particular expense was inappropriate, the expense item must be adjusted without regard to what other expenses may be changed. If TXU wished to adjust any of these expenses, it was free to do so if it could support the change. Dallas argued that TXU chose to use a blanket approach in GUD 9400. Therefore, any piece the Intervening parties chose to investigate was reasonable and that it was not the intervening parties' burden to establish TXU's evidence relating to Business Services expenses.[324]

Dallas complained that TXU's use of different allocators on the same account made review difficult, especially when the applied allocator changed from period to period and when the particular services

[324] Dallas Exhibit 1 at 47-64 and attachment JP-4.

provided under an Activity/Project changed over time.[325] Not all of the projects identified in TXU's request are appropriate for inclusion because expenses vary from year to year and should, therefore, be evaluated for inclusion in rates on the basis of whether they are reasonable and necessary as ongoing expenses. Dallas argued that because 2002 was not a typical year, adjustment of TXU's request is appropriate.[326] As a test for reasonableness of these charges, Dallas compared costs proposed in this proceeding with allocation of costs in two previous proceedings: GUD 9313 and Public Utility Commission (PUC) Docket No. 22350. Dallas reasoned that these were the two most recent presentations to state regulatory agencies by TXU Gas as to the charges it paid to TXU Business Services. Dallas argued that a snapshot of 2002 costs may not represent typical or reasonable expenses for the ongoing operation of TXU Business Services costs that have been allocated to Distribution and Pipeline. Dallas suggested that one consideration of the reasonableness of expenses is to compare the same area of cost responsibility for prior periods.[327]

Dallas argued that TXU's statement that TXU Business services does not make a profit is misleading. Dallas argued that TXU Business Services earned a profit for TXU due to hidden costs of TXU Business Services, including return (i.e, an interest cost). Dallas noted that TXU Business Services charged TXU Gas and the other affiliates amounts for rent on the TXU properties building in downtown Dallas; return on the assets of TXU Business Services; income taxes; ad valorem property taxes; and depreciation. Dallas argued that TXU failed to identify these amounts that are included in TXU Gas' proposed rates. Dallas argued that if TXU Business Services is only allocating actual incurred costs at no profit, then it must disclose the amounts and percentages added for overhead. TXU did not do so, and is therefore asking the Commission to authorize a return on investment which is not disclosed.

Dallas reviewed the costs, approximately $29 million, charged by TXU Business Services and identified mis-allocations; failure to normalize excessive costs occurring during the test year; and failure to capitalize portions of costs that require capitalization rather than full expensing. Dallas argued that the amounts assigned to TXU Gas should be reduced by a combined total of $4,262,265 ($2,790,051 for Distribution revenue requirements and $1,472,214 for Pipeline revenue requirements).[328]

Dallas explained its normalization process: Considering the projects associated with specific and identifiable regulated affiliates and the equivalent unregulated affiliates that perform services that were previously regulated, Dallas analyzed charges to the projects for the test year (calendar year 2002), the test data provided in GUD 9313 (test year ending September 30, 2001), and the base year for the unbundled cost of service (UCOS) filing by TXU Electric before the Public Utility Commission (test year ending September 30, 1999).

Dallas observed that the level of expenses charged to the various affiliates varied significantly, depending on what was transpiring during those particular periods. Dallas noted that in calendar year 2002, Distribution was assigned 38.5 percent of the Regulatory Affairs cost attributable to the various electric and gas entities. When the same projects were reviewed at a time frame approximately one year earlier,

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[325] Dallas Exhibit 1at 48.
[326] Dallas Initial Brief at 46-47; Tr. Vol. 4 at 41-53 (Jan. 29, 2004).
[327] Dallas Exhibit 1at 48-49.
[328] Dallas Exhibit 1 at 47-64 and attachment JP-4 at 1-8.

the portion allocated to Distribution was 28.7 percent. Dallas considered that when the utility's electric affiliate was undergoing its restructuring analysis, the percent of costs for the same projects dropped to approximately 26.4 percent for Distribution. Dallas commented that TXU's electric affiliates built into their rates and tariffs an amount in excess of the total for both gas and electric related Regulatory Affairs in this case.

Dallas looked at three different time frames for these same projects or services provided by Regulatory Affairs and averaged the percent assignment in each year to Distribution and Pipeline. Then Dallas applied that average for the Distribution and Pipeline projects to the total TXU Business Services amounts for these projects. Distribution was assigned $1,985,796, or 38.5 percent of the total similar type expenses during the test year. The average of the three individual test years assignable to Distribution was 31.20 percent. Dallas applied the 31.20 percent proxy for a normalized allocation to the current test year total for the comparable cost categories, resulting in only $1,608,981 being assignable to Distribution. Dallas's calculation resulted in a $376,815 reduction to the cost level for Distribution that was reflected in Exhibit SNR-2. Applying the same procedure for Pipeline resulted in an increase in expense of $20,413.

With regard to federal income tax (FIT), Dallas challenged inclusion of any amount for tax return preparation because TXU had failed to provide information relating to the savings benefit the corporation would recognize through a consolidated tax filing. Dallas argued that TXU should not be rewarded with Commission approval for inclusion of the tax account when TXU presented no evidence on the matter.

Dallas Exhibit 1 at page 50 and Dallas's March 8, 2004, Initial Brief at page 47 provide several items Dallas considered to be in error or in need of correction or normalization and provided the City's recommendation.[329]

- Projects 1090000, 10921000, 109230000– Regulatory Costs should be normalized and consequently reduced by $1,016,628 Distribution and $24,975 Pipeline.
- Projects 53900000, 60320000– Tax Preparation Costs should be disallowed in the amounts of $1,014,760 for Distribution and $713,839 for Pipeline.
- Project 60400000–TXU Corporate Controller Property Accounting should have been capitalized, in part, resulting in a reduction to Distribution expense of $294,081, a reduction of Pipeline expense of $420,553, and an appropriate change to invested capital.
- Project 54200000– Corporate Services Administrative Claims and Legal Administrative Services should be normalized resulting in Distribution expense reduction of $372,544 and Pipeline increase of $5,324.
- Project 19920000– TXU Acquisition Services cost should have been capitalized, in part, to reduce Pipeline expenses by $317,168 and increasing invested capital by a corresponding amount.
- Project 21820000– TXU Brand corporate identification expense should be disallowed in its entirety, resulting in a reduction to Distribution of $257,102.
- Project 83010000– Business Services Procure Resources Administration should be normalized resulting in an adjustment of $17,496 Distribution and $175,305 Pipeline.
- Project 43000000– Information Technology expense should be normalized by reducing the Distribution expenses by $96,885 and by reducing the Pipeline expenses by $65,162.

329 Based upon Dallas Exhibit 1 at 47-63 and attachment JP-4.

Overview of ACC's Arguments Regarding Business Services Issues

ACC argued that TXU Gas failed to show that the costs allocated to TXU Gas from TXU Business Services that were included in TXU's requested cost of service were reasonable and necessary. ACC compared the costs presented by TXU to the costs for the same services in the two years prior to the test year. ACC then recommended adjustments to test year expenses in four categories: non-recoverable expense, non-recurring expense, cost adjusted expenses, and allocation adjusted expense. In total, ACC recommended adjustments totaling $8,477,490 ($5,418,217 for Distribution and $3,059,273 for Pipeline) relating to TXU Business Services costs that were allocated to TXU Gas.[330] ACC noted that TXU had agreed to the recommended changes to 10970001 – Austin Regulatory – Lobbyist Activity and to 10921000 – Rates & Regulatory – Admin.

To TXU's objections that it had not recommend any adjustments to increase TXU Business Services' allocations to TXU Gas, ACC responded that it is the utility's obligation to present the test year expense adjustments it desired because Intervenors were under no obligation to assist TXU to increase its rates. ACC also argued that whether TXU Business Services operates at "no profit" is irrelevant. Instead, the relevant question is whether the costs it seeks to pass to TXU Gas' customers are reasonable.[331]

ACC identified non-recoverable expenses in six accounts and, on the basis that ratepayers should not pay for these non-recoverable expenses, recommended an overall disallowance adjustment to Distribution of $396,282 and to Pipeline of $75,899, for a total reduction of $472,171.[332]

ACC identified non-recurring expenses in four accounts. These projects may have provided benefit to gas customers at the time they occurred, but because the activity is not recurring, the expenses should be disallowed. For non-recurring expenses, ACC recommended an overall disallowance adjustment to Distribution of $192,236 and to Pipeline of $132,176, for a total of $324,412.[333]

ACC identified thirteen accounts it considered to contain unreasonably high costs when compared with previous years. ACC recommended overall cost adjustments to Distribution's expenses of $2,355,988 and to Pipeline's of $2,392,546, for a total of $4,748,534.[334]

ACC identified thirteen accounts it considered to have an unreasonable allocation factor during the test year. ACC recommended overall cost adjustments to Distribution's expenses of $2,473,711 and to Pipeline's of $458,662, for a total of $2,932,373.[335]

Overview of ATM's Arguments Regarding Business Services Issues

ATM stated that it supports the TXU Business Services adjustments recommended by Dallas and ACC.[336]

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[330] ACC Exhibit 4, Table 4, at 34.
[331] ACC Reply Brief at 67-68 (Mar.17, 2004).
[332] ACC Initial Brief at 90-92 (Mar. 8, 2004); ACC Exhibit 4 at 34-36; TXU 15 at 38-63 (SNR-1).
[333] ACC Initial Brief at 92-93 (Mar. 8, 2004); ACC Exhibit 4 at 34, 37-38; TXU 15 at 38-63 (SNR-1).
[334] ACC Initial Brief at 93-106 (Mar. 8, 2004); ACC Exhibit 4 at 34, 38-42; TXU 15 at 38-63 (SNR-1).
[335] ACC Initial Brief at 107-128 (Mar. 8, 2004); ACC Exhibit 4 at 34, 43-47; TXU 15 at 38-63 (SNR-1).
[336] ATM Initial Brief at 57 (Mar. 8, 2004).

Overview of Examiners' Analysis and Recommendation
TXU Gas has the burden to prove that the expenses associated with TXU Gas Services are reasonable, necessary, and in accordance with the affiliate transaction standard. It is not the obligation of the Intervening parties to make arguments on behalf of the utility in this proceeding or to disprove TXU's evidence.

It is a well established ratemaking principle that expenses included in a utility's cost of service are limited to those necessary for providing service to customers and reasonable in amount. The Examiners reviewed all the evidence in the record relating to the affiliate transactions and charges between TXU Business Services and TXU Gas. The Examiners studied the equity of the billing process and considered whether the costs assessed were reasonable and necessary expenses for the provision of gas utility services. Having examined all the evidence presented by TXU and the Intervenors, the Examiners find that in some instances, as discussed in the next section, TXU failed to meet its burden of proof to show that all costs were reasonable and necessary. The Examiners also find that it is not appropriate for non-recurring expenses to be included in the cost of service. In other words, one-time expenses should not be included in the utility's cost of service.

Subsection B: TXU Business Services' Accounts

TXU encouraged the Examiners and Commission to review, in detail, the recommendations made by the utility, Dallas, and ACC. This subsection provides that detailed review. The TXU project number, name, and description, along with parties' positions and recommendations, are summarized. The information was derived from the entire body of the evidence including TXU Exhibit 15 and attachments SNR-1 and SNR-2; TXU Exhibit 28 and attachments; ACC Exhibit 4 and attachments KJN-5 and KJN-6 including RFI responses; and the parties' March 8, 2004, briefs and March 17, 2004, reply briefs.

10900000 TUS Regulatory Administration
Expenses associated with regulatory support services for the Distribution business unit, Transmission business unit, and Pipeline business unit, such as manual and electronic filings with the Public Utility Commission, filings with FERC, printing of filings, and maintaining LAPIS, a file retrieval system.

TXU:
Activity/Projects 10921000, 10923000, 10984000, 10984000, and 10985000 are discussed in greater detail under the respective Activity/Project accounts, that follow within this Business Services section. TXU sought to include regulatory administration costs including:
Activity/Project 10900000 - Distribution: $119,080 and Pipeline: $119,080
Activity/Project 10921000 - Distribution: $811,772
Activity/Project 10923000 - Distribution: $163,460 and Pipeline: $21,772
Activity/Project 10984000 - Distribution: $1,985,796
Activity/Project 10985000 - Pipeline: $69,067

TXU disagreed with Dallas's proposal that portions of the amounts billed to Distribution and Pipeline for TXU Business Services' Regulatory Affairs Organization be disallowed. TXU noted that its explanation for this project is tied to Activity/Project 10984000. TXU argued that Dallas's "correlation approach" is flawed in that, at varying times throughout the 4-year period that Dallas selected as a "normalization" period, organizations that provide Regulatory Affairs services resided within TXU Business Services and/or the various business units they serve, e.g., Oncor Electric Delivery and TXU Energy. Therefore, Dallas's comparative analysis is unfounded and incomplete. TXU argued that the only appropriate adjustment to the Regulatory Affairs expenses assigned to Distribution is the reduction of $585,605 (See discussion at Project/Activity 10921000, Rates & Regulatory-Admin, below). TXU stated that the remaining amounts billed by TXU Business Services' to Distribution and Pipeline are reasonable, necessary, and reflect an appropriate level of expense for this service.

Dallas's Position

Dallas addressed the regulatory and administrative regulatory related costs together, including Projects 10900000, 10921000, 10923000, 10984000, and 10985000.[337] Dallas considered the projects associated with specific and identifiable regulated affiliates and the equivalent unregulated affiliates that perform services that were previously regulated.

Dallas determined that the level of expenses chargeable to the various affiliates varied significantly depending on what was transpiring during those particular periods. In calendar year 2002, Distribution was assigned 38.5 percent of the Regulatory Affairs cost attributable to the various electric and gas entities. However, when the same projects were reviewed at a time frame approximately one year earlier, Dallas found the allocable portion to Distribution to have been 28.7 percent. When the utility's electric affiliate was undergoing its restructuring analysis, the percent of costs for the same projects dropped to approximately 26.4 percent for Distribution.

Dallas noted that TXU's electric affiliates' rate tariffs reflect an amount in excess of the total for both gas and electric related Regulatory Affairs in this case. Thus, Dallas concluded, if the Commission declined to assign any amount to Distribution and Pipeline in GUD 9400 for Projects 10984000 and 10985000, TXU Corporation would already be compensated for all the activities it claimed to have performed during 2002.

Dallas analyzed charges to the projects for the test year (calendar year 2002), the test data provided in GUD 9313 (test year ending September 30, 2001), and the base year for the unbundled cost of service (UCOS) filing by TXU Electric before the Public Utility Commission (test year ending September 30, 1999). Then, Dallas applied that average to the total TXU Business Services amounts for these projects. Dallas assigned $1,985,796, or 38.5 percent, to Distribution of the total similar type expenses during the test year. The average of the three individual test years assignable to Distribution was 31.20 percent. Applying the 31.20 percent proxy for a normalized level to the current test year total for the comparable cost categories resulted in only $1,608,981 being assignable to Distribution. Therefore, Dallas recommended a $376,815 reduction to the cost amount proposed by TXU. Dallas applied the same calculation methodology to Pipeline. The result was an increase in expense of $20,413 to Pipeline.

Dallas recommended that Regulatory Costs should be normalized and consequently reduced by $1,016,628 Distribution and $24,975 Pipeline.

Examiners' Recommendation

TXU has the burden to prove that its expenses are reasonable and necessary for the provision of gas utility

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[337] Dallas Exhibit 1, Schedule JP-4 at 2 of 8.

service. TXU reported that Project 10900000, TUS Regulatory Administration, is for regulatory support services expenses for the Distribution business unit, Transmission business unit, and Pipeline business unit these support services include manual and electronic filings with the Public Utility Commission, filings with FERC, printing of filings, and maintaining LAPIS, a file retrieval system. However, TXU did not provide sufficient evidence for determining which portions of this Project are attributable to gas utility customers. TXU failed to explain how Distribution expense of $119,080 and Pipeline expense of $119,080 is either reasonable or necessary. Therefore, the Examiners recommend the Commission disallow these expense amounts, in total. The Examiners' recommendations regarding Projects 10921000, 10923000, 10984000, 10984000, and 10985000 are found with those Projects.

10920109 City of Denton Litigation Suit

Expenses associated with regulatory work in support of the City of Denton franchise fee litigation. This included litigation, employee expenses, and office support.

TXU's Position

TXU requested Commission approval of $10,887 for Distribution, for inclusion in the rates paid by TXU Gas customers.

ACC's Position

ACC argued that this project was completed, and was not expected to be recurring. The test year contained only 4 percent of the project expenses that were incurred since 2000. This item may have provided a benefit to TXU Gas customers at the time the expense was incurred, but it is not an ongoing project or activity expense. ACC argued that because the activity was completed and was not recurring, it would be inappropriate to continue to recover these expenses from ratepayers. Therefore, it is reasonable to remove these expenses from TXU Gas' cost of service. ACC recommended the following adjustments as non-recurring expense:

Distribution: ($10,887)
Pipeline: -0-

Examiners' Recommendation

TXU failed to provide evidence showing that the $10,887 costs associated with the City of Denton Litigation Suit were reasonable and necessary. TXU did not dispute that this was no longer an ongoing expense, nor did TXU rebut ACC's argument that because the activity was completed and was not recurring, it would be inappropriate to continue to recover these expenses from ratepayers. Having reviewed the evidence, the Examiners find that it is reasonable for the Commission to disallow TXU's request for $10,887 for expenses associated with regulatory work in support of the City of Denton franchise fee litigation.

10921000 Rates & Regulatory-Admin

Provides management of rates and regulatory affairs before regulatory authorities, including rate and tariff proceedings, rulemakings, reporting, customer complaints, and other regulatory issues.

TXU's Position

TXU requested Commission approval of $811,772 for Distribution , for inclusion in the rates paid by TXU Gas customers. TXU disagreed with Dallas's position that a portion of the amounts billed to Distribution regarding regulatory administration expenses should be disallowed based on an increase in the pro rata share assigned to Distribution in 2002 compared with the average of the test year, the GUD 9313 test year (ending September 30, 2001), and Public Utility Commission Docket No. 22350 test year (ending September 30, 1999). TXU argued that Dallas's recommendation was a "piecemeal" approach to ratemaking, ignored the Commission's test-year-based ratemaking principles, and presented incorrect information. TXU argued that the data Dallas used to "normalize" 2002 are four years old. Dallas provided no evidence that these data reflect current expense levels; rather that this average is lower than the 2002 levels.

TXU argued that the only appropriate adjustment to the Regulatory Affairs expenses assigned to Distribution is the reduction of $585,605 (See also discussion at Project/Activity 10900000 regarding TUS Regulatory Administration).

Allied Coalition of Cities's Position
ACC noted that TXU acknowledged that approximately $1.27 million in legal expenses were charged to this project that should have been assigned to Oncor Electric and TXU Energy only. ACC represented that TXU agreed to make this adjustment. ACC argued that the total allocated to TXU Gas Distribution should be $226,167. ACC recommended the following adjustment to derive an allocation-adjusted expense:

Distribution:	($585,605)
Pipeline:	-0-

Dallas's Position
As discussed under Activity/Project 10900000, above, Dallas considered the projects associated with specific and identifiable regulated affiliates and the equivalent unregulated affiliates that perform services that were previously regulated. Dallas analyzed charges to the projects for the test year (calendar year 2002), the test data provided in GUD 9313 (test year ending September 30, 2001), and the base year for the unbundled cost of service (UCOS) filing by TXU Electric before the Public Utility Commission (test year ending September 30, 1999). Dallas recommended that Regulatory Costs (Projects 1090000, 10921000, 109230000) should be normalized and consequently reduced by $1,016,628 Distribution and $24,975 Pipeline.

Examiners' Recommendation
The Examiners find that the $585,605 disallowance recommended by ACC and agreed to by TXU is supported by the evidence and should be approved. TXU's errata spreadsheets in TXU Exhibit 61 already reflect this modification.

10923000 Regulatory Support
Expenses associated with provision of regulatory support for all TXU and Oncor businesses, such as manual and electronic filings with regulatory agencies, printing of filings and development and maintenance of monitoring and retrieval systems for regulatory data.

TXU's Position
TXU requested Commission approval of $163,460 for Distribution and $21,772 for Pipeline for inclusion in the rates paid by TXU Gas customers. TXU argued that Dallas's recommendation was a "piecemeal" approach to ratemaking, ignored the Commission's test-year-based ratemaking principles, and presented incorrect information. TXU argued that the data Dallas used to "normalize" 2002 are four years old. Dallas provided no evidence that these data reflect current expense levels; rather that this average is lower

than the 2002 levels. For a complete discussion of TXU's position, please see the discussion included under Activity/Project No. 10984000, Reg Affairs-TXU Gas Distribution.

Dallas's Position

As discussed under Activity/Project 10900000, above, Dallas considered the projects associated with specific and identifiable regulated affiliates and the equivalent unregulated affiliates that perform services that were previously regulated. Dallas analyzed charges to the projects for the test year (calendar year 2002), the test data provided in GUD 9313 (test year ending September 30, 2001), and the base year for the unbundled cost of service (UCOS) filing by TXU Electric before the Public Utility Commission (test year ending September 30, 1999). Dallas recommended that Regulatory Costs (Projects 1090000, 10921000, 109230000) should be normalized and consequently reduced by $1,016,628 Distribution and $24,975 Pipeline.

Examiners' Recommendation

TXU did not provide evidence demonstrating that $163,460 is a reasonable expense for Distribution and $21,772 is a reasonable expense for Pipeline for costs for manual and electronic filings with regulatory agencies, printing of filings, and development and maintenance of monitoring and retrieval systems for regulatory data as those expenses apply to the TXU gas utility service. TXU failed to meet its burden. Therefore, it is reasonable for the Commission to disallow $163,460 Distribution costs and $21,772 Pipeline costs.

10926062 Gas Bill Charges

This project captured costs associated with the development and design of a new gas bill, in accordance with the Commission's Order in GUD 8145. This project includes expenses for consultants, legal assistance, office support, and employee expenses.

TXU's Position

TXU requested Commission approval of $6,805 for Distribution, for inclusion in the rates paid by TXU Gas customers. TXU argued that the amount of $6,805 related to Activity/Project 10926062 was deferred on the books of Distribution and is therefore not included in TXU Gas-Distribution's requested cost of service. To disallow these costs would understate TXU Gas-Distribution's cost of service requirement.

ACC's Position

ACC acknowledged TXU's statement that it deferred $6,805 on the books of TXU-Distribution. ACC stated that if TXU has not included the expense in the cost of service and does not intend to recover this expense from ratepayers, then its recommendation can be withdrawn.

ACC argued, in the alternative, that this project is completed and is not expected to be recurring. In test year 2002, only 2 percent of the project expenses were incurred since the project began in 2001. ACC argued that this item may have provided a benefit to TXU Gas customers at the time the expense was incurred, but it is not an ongoing project or activity expense. ACC argued that because the activity was completed and was not recurring, it would be inappropriate to continue to recover these expenses from ratepayers. Therefore, it is reasonable to remove these expenses from TXU Gas' cost of service. ACC recommended the following adjustment to exclude non-recurring expense:

Distribution: ($6,805)
Pipeline: -0-

Examiners' Recommendation

Having considered the evidence, the Examiners find that Project 10926062, Gas Bill Charges, was a short term project rather than a recurring, on-going activity. Therefore, this expense should be disallowed. It is reasonable for the Commission to disallow TXU's request for $6,805 Distribution expense for development and design of a new gas bill.

10970001 Austin Reg.-Lobbyist Activity

Services include lobbying activities associated with Austin regulatory lobbyist activities.

TXU's Position

TXU requested Commission approval of $276 for Distribution for inclusion in the rates paid by TXU Gas customers.

ACC's Position

TXU acknowledges that these costs should be booked below the line, but were incorrectly booked to TXU Gas Distribution account 923. ACC recommended the following adjustment to remove non-recoverable expense:

Distribution:	($276)
Pipeline:	-0-

Examiners' Recommendation

The Examiners find that, based on the evidence presented, lobbying activities associated with Austin regulatory lobbyist activities, are non-recoverable expenses. TXU agreed to ACC's proposed disallowance. Having reviewed the evidence, the Examiners find that it is reasonable for the Commission to disallow TXU's request for costs of $276 for Austin regulatory lobbyist activities as a non-recoverable expense. TXU's errata spreadsheets in TXU Exhibit 61 already reflect this modification.

Activity/Projects 10984000 and 10985000 are considered together.

10984000 Regulatory Affairs-TXU Gas Distribution

Expenses incurred with the management of rates and regulatory affairs before the regulatory authorities which include rate and tariff proceedings, fuel proceedings, rulemakings, reporting, customer complaints, and deregulation issues impacting TXU Gas Distribution.

10985000 Regulatory Affairs - Pipeline

Expenses incurred with the management of rate and regulatory affairs before regulatory authorities and which include rate and tariff proceedings, rulemakings, reporting, customer complaints, and deregulation issues impacting TXU Lone Star Pipeline Company. Regulatory support services are necessary because of the significant impact of regulatory actions on the cost of electric service in Texas. The services are also necessary to keep TXU Lone Star Pipeline Company informed as to the new laws and regulations with which it must comply.

TXU's Position

TXU requested Commission approval of $1,985,796 for Distribution (Activity/Project 10984000) and $69,067 for Pipeline (Activity/Project 10985000), for inclusion in the rates paid by TXU Gas customers.

TXU disagreed with Dallas's position that a portion of the amounts billed to Distribution regarding regulatory administration expenses should be disallowed based on an increase in the pro rata share assigned to Distribution in 2002 compared with the average of the test year, the GUD 9313 test year (ending September 30, 2001), and PUC Docket No. 22350 test year (ending September 30, 1999). TXU argued that Dallas's recommendation was a "piecemeal" approach to ratemaking, ignored the Commission's test-year-based ratemaking principles, and presented incorrect information. TXU argued that the data Dallas used to "normalize" 2002 are four years old. Dallas provided no evidence that these data show current expense levels; rather that this average is lower than the 2002 levels.

TXU argued that Dallas created a relationship between the amounts billed to Distribution through Activity/Project 10984000 and TXU Business Services' total Regulatory Affairs expense as presented in this proceeding, Docket No. 9313 before this Commission, and TXU Electric's UCOS filing before the Public Utility Commission of Texas. TXU stated that a correlation does not exist between the amount assigned to Distribution and the total regulatory affairs expense; therefore, TXU Business Services does not assign Distribution costs according to the non-existent correlation.

TXU argued that at varying times throughout the four year "normalization" period, organizations that provide Regulatory Affairs services resided within TXU Business Services and/or the various business units they serve, e.g., Oncor Electric Delivery and TXU Energy. Therefore, Dallas's comparative analysis is unfounded and incomplete.

TXU stated that Activity/Project 10984000 is one example of direct billing-- the service provided through Activity/Project 10984000 is 100 percent dedicated to Distribution. TXU argued that the amounts charged to Distribution through Activity/Project 10984000 remained relatively constant over the four-year period Dallas chose as a normalization period, noting that for the twelve months ending September 30, 1999, September 30, 2001, and December 31, 2002, the amounts billed to Distribution were $2,249,488, $2,311,908, and $1,985,796, respectively.

TXU questioned the legitimacy and reasoning of Dallas approach. TXU observed that Dallas did not remain consistent in its approach to normalization. Dallas did not use the three amounts or average the three amounts to calculate the recommended "normalized" amount. Instead, TXU argued, Dallas created an irrelevant correlation between the percentage of these amounts and an incomplete Regulatory Affairs expense to normalize Distribution's "normalized" Regulatory Affairs expense. TXU presumed Dallas used this approach because it created a disallowance while other methods did not.

Examiners' Recommendation

The Examiners considered the evidence; TXU failed to prove the reasonableness and the necessity of these amounts as applicable to gas utility service. TXU did not provide evidence explaining the connection between electric restructuring issues and the impact upon TXU Gas Distribution. TXU did not provide evidence explaining how these fees differ from rate case expenses that are typically treated separately and are amortized in rate case expense proceedings. TXU averred that regulatory support services are necessary because of the significant impact of regulatory actions on the cost of electric service in Texas and that the services are necessary to keep TXU Lone Star Pipeline Company informed as to the new laws and regulations with which it must comply. The Examiners find that it is the responsibility of TXU Electric to consider the impact of regulatory actions on the cost of electric service. TXU Gas customers should not pay for amounts associated with electric service. TXU did not provide evidence to demonstrate that amounts applicable to electric utility issues were omitted. TXU failed to provide evidence showing that the proposed expense amounts were reasonable. Therefore, it is reasonable for the Commission to disallow expenses of $1,985,796 for Distribution (Activity/Project 10984000) and $69,067 for Pipeline (Activity/Project 10985000).

11700001 Oncor Financial Planning

Expenses associated with Oncor strategic planning, consolidation of financial and business plan information, and financial analysis regarding valuation of assets to be bought or sold.

TXU's Position

TXU requested $215,576 for Distribution and $77,901 for Pipeline. TXU disagreed with ACC's position that a portion of the expenses in this account should be disallowed. TXU observed that the basis for ACC's proposal to disallow the costs is that the costs were higher in 2002 than in 2001. TXU argued that ACC presented no evidence as to why the total costs incurred in 2002 are not reasonable; that costs for this service consist primarily of labor and labor-related expenses; and that this service allows for better management of operations and the associated costs.

TXU noted that the increase in these costs over prior years represented an increased staffing level required to perform the tasks. TXU stated that the total costs associated with Project 11700001 for 2002 are reasonable and necessary and should be included in TXU Gas' requested cost of service.

ACC's Position

ACC observed that total expenses almost doubled between 2001 and 2002, while expenses allocated to Distribution increased 70 percent and Pipeline increased 43 percent over the same period. ACC recommended using the 2001 allocated amounts of $127,092 for Distribution and $54,301 for Pipeline for the adjusted test year amounts. ACC took the position that this project showed an extraordinary level of expense in 2002 that was not representative of ongoing expenses. ACC based its adjustment upon a comparison of the test year allocated expense with prior years' expenses for the same activity. ACC observed that the project may have represented an ongoing activity, but that the test year amount was anomalously high compared to past years. ACC adjusted the test year costs to reflect a more likely level of expense based on historic expenses. ACC recommended the following adjustments to derive cost-adjusted expenses:

Distribution:	($88,484)
Pipeline:	($23,600)

Examiners' Recommendation

The Examiners considered TXU's testimony that the increase in costs over prior years represented an increased staffing level required to perform the tasks. The Examiners find TXU's evidence inadequate because TXU failed to explain why the additional labor was necessary. Statements affirming that the money was spent or that money was spent on labor fail to explain why the requested level of cost was reasonable and necessary; why additional labor was necessary; why the increase was almost doubled in one year's time; or why the allocation to Distribution increased 70 percent and Pipeline increased 43 percent over the same period. Because the evidence presented failed to show that the costs were necessary and reasonable, the Examiners recommend partial disallowance in accordance with ACC's proposal. It is reasonable for the Commission to reduce TXU's request by $88,484 for Distribution and $23,600 for Pipeline.

18130000 Oncor Revenue & Receivables

Expenses associated with maintenance of the financial information management (FIM) accounts receivable system, processing non-customer information system (CIS) payments, and collection services.

TXU's Position

TXU requested Commission approval of $128,775 for Distribution and $535,829 for Pipeline, for inclusion in the rates paid by TXU Gas customers. TXU argued that for both Distribution and Pipeline, expenses for this account increased between 2000 and 2002 because (1) the non-CIS accounts receivable collections process for both Distribution and Pipeline was not achieving the desired collection success rate and (2) the percentage of staff time spent supporting the revenue and receivables function of Distribution and Pipeline increased significantly in 2002. TXU stated that, beginning in 2002, Oncor Revenue & Receivables dedicated three full-time employees to the non-CIS collections process on behalf of Distribution and Pipeline. As a result of the increased staffing levels, non-CIS collections improved. TXU argued that the total costs associated with Activity/Project 18130000 for 2002 are reasonable and necessary and should be included in the requested cost of service.

ACC's Position

ACC noted that after being stable in 2000 and 2001, expenses allocated to Distribution and Pipeline approximately doubled in the test year. ACC recommended using the 2001 allocated amounts of $67,717 for Distribution and $231,868 for Pipeline for the adjusted test year amounts. ACC stated that the extraordinary level of expense in 2002 was not representative of ongoing expenses for this project. ACC based its adjustment upon a comparison of the test year allocated expense with prior years' expenses for the same activity. ACC recommended the following adjustments to derive cost-adjusted expenses:

Distribution: ($61,058)
Pipeline: ($303,961)

Examiners' Recommendation

The Examiners find that the additional costs were needed for increased labor dedicated to the collections process on behalf of Distribution and Pipeline to improve the utility's collection rate. The Examiners recommend the Commission approve TXU's request of $128,775 for Distribution and $535,829 for Pipeline.

18210000 Oncor System Implementation

Expenses for modifying, testing, and implementation of new systems for Distribution and Pipeline. TXU reported that labor expense is the primary driver for costs.

TXU's Position

TXU requested Commission approval of $82,991 for Distribution and an additional $82,991 for Pipeline, for inclusion in the rates paid by TXU Gas customers. TXU argued that from time to time, TXU Business Services establishes a separate Activity/Project to capture costs related to a specific short-term project. Capturing these costs separately provides management with the necessary information with which to optimally manage a project and/or provides for more specificity when necessary. The costs included in Activity/Project 18210000 consisted almost entirely of labor and labor-related expenses for employees working, on an ongoing basis, in the Oncor Controller's function of TXU Business Services. During the period in which employees worked on the Oncor System Implementation project, their costs were captured in Activity/Project 18210000 to provide a tool by which management could better manage these costs.

Prior to working on this project and subsequent to the completion of this project, these employees performed their traditional accounting related activities on behalf of various TXU entities, including TXU Gas - Distribution and TXU Gas - Pipeline. TXU argued that to exclude these ongoing costs from TXU Gas' requested cost of service would understate the utility's required cost of service.

ACC's Position

ACC argued that implementation of this system is a stand alone, non-recurring project. ACC argued that this item may have provided a benefit to TXU Gas customers at the time the expense was incurred, but it is not an ongoing project or activity expense. Now that the activity is completed and is not recurring, it would be inappropriate to continue to recover these expenses from ratepayers. Therefore, it is reasonable to remove these expenses from TXU Gas's cost of service. ACC recommended the following adjustment to remove non-recurring expense:

Distribution: ($82,991)
Pipeline: ($82,991)

Examiners' Recommendation

Having considered the evidence, the Examiners find that Project 18210000 was a short-term project rather than a recurring, on-going activity. Therefore, the expense for it should be disallowed for rate setting. It is reasonable for the Commission to disallow TXU's request for $82,991 for Distribution and $82,991 for Pipeline for modifying, testing, and implementation of new systems under Project 18210000 because it is a non-recurring cost.

19400000 Print Services

Expenses for copies, manuals, labels, and other miscellaneous printing.

TXU's Position

TXU requested Commission approval of $71,398 for Distribution and $34,466 for Pipeline, for inclusion in the rates paid by TXU Gas customers. TXU argued that rate case expenses have been excluded from TXU Gas's requested cost of service. TXU stated that the rate filing package associated with this Docket No. 9400 was printed in the second quarter of 2003. Therefore, the costs for that print job could not have been included in 2002 expenses. TXU argued that printing costs associated with the printing of any rate case filing is charged to the TXU Business Services' Activity/Project directly associated with that rate case. TXU argued that ACC's proposed disallowance of $58,249 for Distribution and $22,669 for Pipeline should be rejected.

ACC 's Position

ACC noted that total expenses more than doubled between 2001 and 2002. However, the expenses allocated to Distribution increased more than fivefold and those allocated to Pipeline almost tripled between 2001 and 2002. ACC argued that the increased printing costs reflected in the test year were related to this GUD 9400 rate case and to the regional cases. ACC recommended that a more reasonable level of expenses for the adjusted test year would be the 2001 amount of $13,149 for Distribution and $11,797 for Pipeline. ACC stated that this project showed an extraordinary level of expense in 2002 that was not representative of ongoing expenses. ACC based its adjustment upon a comparison of the test year allocated expense with prior years' expenses for the same activity. ACC observed that the project may have represented an ongoing activity, but that the test year amount was anomalously high compared to past years. ACC adjusted the test year costs to reflect a more likely level of expense based on historic expenses.

ACC recommended the following adjustment to derive cost adjusted expenses:

Distribution: ($58,249)
Pipeline: ($22,669)

Examiners' Recommendation

TXU explained that the increased costs were not due to rate package printing. TXU also stated affirmatively that these costs were reasonable. However, statements affirming that the money was spent fail to explain why the requested level of cost was reasonable and necessary and fail to explain why additional printing services were needed in the test year. TXU failed to explain what caused the cost of printing services to double, why the allocation to Distribution increased fivefold between 2001 to 2002, or why the allocation to Pipeline almost tripled between 2001 to 2002. TXU failed to provide probative evidence that the costs were both necessary and reasonable. The Examiners recommend partial disallowance in accordance with ACC's proposal. It is reasonable for the Commission to reduce TXU's request by $58,249 for Distribution and $22,669 for Pipeline.

19420000 Printing Services-Forms Management

Services associated with the design and production of standardized forms.

TXU's Position

TXU requested Commission approval of $165,939 for Distribution and $18,919 for Pipeline, for inclusion in the rates paid by TXU Gas customers. TXU argued that ACC improperly used a time period that was two years prior to the test year, simply because the result is a lower percentage to apply to test year levels than if year 2001 were used. TXU stated that Activity/Project 19420000 is assigned to each TXU entity based on the cost of the individual jobs performed on behalf of that entity. TXU argued that the costs included in Distribution's requested cost of service for this Activity/Project are reasonable and necessary, that ACC presented no contravening evidence, and ACC's proposed disallowance should be rejected.

ACC's Position

ACC pointed out that total expenses increased from approximately $294,000 in 2000 to $348,000 in 2002, an 18 percent increase over two years. At the same time, the amount allocated to Distribution increased almost fivefold. ACC compared the test year 2002 allocation factor with prior years' allocations for the same activity. ACC observed that either an allocation factor changed appreciably during the test year, or the allocation factor to Distribution or Pipeline was incorrect. ACC assigned a revised allocation factor based on the prior years' allocations to yield a more equitable assignment of costs. ACC recommended that the 2000 Distribution allocation of 11.75 percent be applied to the test year total of $347,541 for allocated expenses of $40,836. ACC recommended the following adjustment to decrease the allocated Distribution expense from $165,939 to $40,836:

Distribution: ($125,103)
Pipeline: -0-

Examiners' Recommendation

TXU offered no evidence explaining the significant increase of approximately 18 percent in these project costs in two years. TXU's arguments that costs for this project are assigned based on the cost of the individual jobs performed on behalf of that entity do not demonstrate reasonableness or necessity. TXU provided no evidence to show how or why these increased costs for services associated with the design and production of standardized forms is reasonable and necessary for the provision of gas services. The Examiners recommend the Commission approve the adjustments, consistent with ACC's recommendation.

19650000 Vehicle Graphics Changeout

Expenses associated with development of a plan with implementation and staffing to convert vehicle graphics from TXU to Oncor. Oncor was created to support the transition to the restructured electric industry.

TXU:

TXU requested Commission approval of $2,709 for Distribution and $903 for Pipeline, for inclusion in the rates paid by TXU Gas customers. TXU argued that the expenses incurred to provide the services performed through Activity/Project 19650000 are not solely costs incurred as a result of electric restructuring; rather, the costs consist of four months' labor and labor-related costs for one individual who works within the Administrative Services' Transportation Administration organization.

TXU Business Services creates, when appropriate, a new short-term Activity/Project to capture costs for the purposes of management control and for lending greater specificity to its billing methodologies. TXU argued that the costs identified as Activity/Project 19650000 were not incremental costs incurred by TXU Business Services. Rather, they are costs incurred on a regular and ongoing basis, and are captured in a separate Activity/Project in order to lend specificity to the billing of those costs during the short-term project period.

TXU explained that following completion of the project, the individual returned to his normal work duties on behalf of the TXU entities served by this organization, including TXU Gas - Distribution and TXU Gas - Pipeline. TXU argued that disallowing the costs in this project would understate the ongoing known and measurable costs incurred in the provision of TXU Business Services' Activity/Project 19600000 – Transportation Administration. Therefore, TXU stated, these costs should not be disallowed.

ACC's Position

Because Oncor was created to support TXU's electric restructuring, these costs should be borne only by TXU's electric company affiliate and electric rate customers. This project provided no benefit to TXU Gas customers. None of the costs assigned by TXU Business Services to TXU Gas (Distribution or Pipeline) should be passed to TXU Gas customers. ACC recommended the following adjustments on the basis that these are non-recoverable expenses:

Distribution: ($2,709)
Pipeline: ($903)

Examiners' Recommendation

TXU failed to prove that its request for expenses associated with converting vehicle graphics from TXU to Oncor is a necessary and reasonable cost of gas utility service to be included in rates. Conversion of vehicle graphics from TXU to Oncor is part of TXU's transition to electric restructuring. TXU's electric division retained the familiar "TXU" name. Regulated gas utility customers should not pay for costs created by TXU's business separation resulting from electric restructuring. Having reviewed the evidence, the Examiners find that it is reasonable for the Commission to disallow TXU's request for Distribution cost of $2,709 and Pipeline's cost of $903, as a non-recoverable expense.

19920000 TXU Acquisition Services

Acquire the properties essential for the construction of all affiliates facilities, excluding TXU Electric Distribution (ESD) and TXU Gas (LSGD), at the lowest possible cost and with minimal litigation and negotiate the economic settlement of construction damage claims. Responsibilities include deed searches, management of land rights and interests, encroachment reporting and management, preparation of releases and exclusions from easements, and renegotiation of relocation agreements.

TXU's Position

TXU requested Commission approval of $343,684 for Pipeline, for inclusion in the rates paid by TXU Gas customers. TXU questioned Dallas's position that $317,168 of the amount billed to Pipeline in this account be capitalized. TXU stated that capital expenditures relate to the acquisition of an asset, the benefit of which extends over one or more accounting periods beyond the current period. TXU argued that, in addition to facilitating the acquisition of right-of-way on behalf of TXU entities, TXU Business Services' Property Management Department also provides ongoing land management services, including prevention of easement encroachment, easement maintenance, protection and prevention of pipe erosion, and highway relocations. TXU argued that because Pipeline has not been in an intensive right-of-way acquisition mode, the majority of the services performed on behalf of Pipeline through Activity/Project 19920000 have been operational in nature and should not be capitalized.

Dallas's Position

Dallas argued that a significant portion of the costs of this project should have been capitalized. First, Dallas noted that this particular project number did not exist in the prior case, GUD 9313, because the expense was reflected elsewhere in the Administrative Service - Administrative Department of TXU Business Services. Dallas reasoned that the project number was created to provide the same service as in Project 19910000-TXU Right of Way Services.

Dallas noted that in Exhibit SNR-1 at page 7, the project descriptions for TXU Right of Way Services and TXU Acquisition Services are identical, except that TXU Acquisition Services excluded the electric and gas Distribution utilities. However, when TXU allocated the costs from TXU Business Services for this same type of service (Project 19910000) to Distribution, TXU significantly reduced the cost in recognition that the types of activities reflected are the type that should be capitalized.

Dallas compared Exhibit SNR-2 and an RFI response about Project 19910000, and noted that Distribution expensed only 7.72 percent of the cost assigned from TXU Business Services. Dallas concluded this is logical because the activities in the Project description are usually capitalized. Dallas recommended that the same expense/capitalization ratio applied to Project 19910000, which has the same description of the services provided but for Distribution, also be applied to the cost allocated from TXU Business Services for Project 19920000 to Pipeline, resulting in a $317,168 reduction to Pipeline expenses and a corresponding increase to invested capital.[338]

[338] Dallas Exhibit 1, Schedule JP-4 at 6 of 8.

Examiners' Recommendation

TXU did not provide adequate evidence or information for analysis of what portion of Project 19920000, TXU Acquisition Services, is for property acquisition and what portion is for property management. The Examiners are unable to determine which amounts, if any, TXU should have capitalized. In absence of such information, it is reasonable that the Commission implement Dallas's recommendation. The Examiners recommend that the Commission reduce Pipeline expense by $317,168 and make a corresponding increase in Pipeline invested capital (Account 36502, Land Rights– Transmission).

20043300 Communications-INET Services

Labor and labor-related expenses associated with supporting the INET communications systems, providing TXU internet and intranet maintenance and development.

TXU's Position

TXU requested Commission approval of $335,044 for Distribution and $149,434 for Pipeline, for inclusion in the rates paid by TXU Gas customers. TXU argued that in 2001, the INET project was still in development and the development-related costs were capitalized. Once the system was implemented, the costs were considered to be operational and were billed to the TXU entities using the services. The billing methodology for Activity/Project 20043300 changed from a weighted average of gross revenues and global headcount in 2001 to a weighted average of desktops per business unit (a surrogate for the headcount of those using the service) in 2002. The change was made to improve the precision with which this service could be billed to users. TXU argued the total costs associated with Activity/Project 20043300 for 2002 are reasonable and necessary and should be included in TXU Gas requested cost of service.

ACC's Position

ACC noted that total expenses increased almost fourfold between 2001 and 2002. Expenses allocated to Distribution increased almost seven times and those allocated to Pipeline increased more than ten times between 2001 and 2002. ACC recommended that a more reasonable level of expenses for the adjusted test year would be the 2001 amount of $50,475 for Distribution and $14,209 for Pipeline. ACC stated that this project showed an extraordinary level of expense in 2002 that was not representative of ongoing expenses. ACC based its adjustment upon a comparison of the test year allocated expense with prior years' expenses for the same activity. ACC observed that the project may have represented an ongoing activity, but that the test year amount was anomalously high compared to past years. ACC adjusted the test year costs to reflect a more likely level of expense based on historic expenses. ACC recommended the following adjustment to derive cost adjusted expense amounts:

Distribution: ($284,569)
Pipeline: ($135,224)

Examiners' Recommendation

Having considered the evidence, the Examiners find the significant increase to be reasonable because it was due to TXU's treatment of that expense once the INET project development had been completed. It is reasonable for the Commission to approve $335,044 for Distribution and $149,434 for Pipeline for Communications-INET Services, as requested by TXU.

20043301 INET-Global

Expenses associated with the continued maintenance and hardware needs of the global portion of the INET project.

TXU's Position

TXU requested Commission approval of $48,695 for Distribution and $21,718 for Pipeline, for inclusion in the rates paid by TXU Gas customers. TXU stated that services provided through Activity/Project 20043301 are pertinent to all TXU employees across the globe while those provided through Activity/Project 20043302 are attributable to those TXU employees residing in North America only. The costs are separated into these two different activities/projects in order to provide the greatest level of specificity possible. Therefore, ACC's proposed disallowance of these costs should be denied.

TXU argued that the purpose of any TXU Business Services' Activity/Project is to bill each subsidiary or division, as accurately as possible, the costs that were incurred on behalf of that entity. Portions of the INET services are pertinent only to TXU entities in North America, while other portions provided service to all TXU entities across the globe, including those in North America. In order to provide a greater level of specificity to its billings, TXU Business Services identified those hardware and software applications that were attributable to all TXU entities across the globe and captured those costs in Activity/Project 20043301. Because those applications were useful to all TXU entities, their costs are assigned to all TXU entities. Other INET applications were only applicable to North American employees. Those costs were captured in Activity/Project 20043302 and billed only to North American TXU entities. The different applications contained in each of the activities/projects was provided in TXU Gas' response to ACC RFI Set No. 3, Question No. 35.

ACC's Position

ACC recalled TXU's statement that there is no overlap between this project and Project 20043302 – INET-North America, which captured expenses associated with the continued maintenance and hardware needs of the North America portion of the INET project. As TXU Gas operates only in North America, gas customers should not be required to support the global portion of the project. This project provided no benefit to TXU Gas customers. None of the costs assigned by TXU Business Services to TXU Gas (Distribution or Pipeline) should be passed to TXU Gas customers. ACC recommended the following adjustments to derive the appropriate expense:

Distribution: ($48,695)
Pipeline: ($21,718)

Examiners' Recommendation

The Examiners find that this is a non-recoverable expense and recommend that the Commission disallow $48,695 Distribution expense and $21,718 Pipeline expense from TXU's requested expense. TXU failed to provide evidence showing that these costs are reasonable and necessary expenditures for the provision of service to gas customers. Because TXU Gas operates only in North America, gas utility customers should not pay for or support the maintenance and hardware needs of the global INET project. TXU provided no probative evidence that its requested amount is reasonable and necessary for the provision of service to its gas utility customers. Therefore, it is reasonable for the Commission to disallow $48,695 from Distribution expense and $21,718 from Pipeline expense.

21820000 TXU Brand/Corporate

Expenses associated with market research, consultation, project management, copy writing, artwork, print/broadcast production, media placement, customer opinion surveys, bill inserts and publications to generate awareness of corporate identity and brand.

TXU's Position

TXU requested Commission approval of $257,102 for Distribution, for inclusion in the rates paid by TXU Gas customers. TXU argued that not all customers know the name of the gas utility in their area and that maintaining a familiarity with the utility companies in their areas is important to new customers who seek utility service when moving to a new town or state. TXU stated that this familiarity is also important to the elderly and children living in a particular area so that they may feel comfortable when they see strangers working in their neighborhoods or when they need assistance in an emergency. TXU argued that the services provided through Activity/Project 21820000, TXU Brand/Corporate, promotes investor awareness that aids in attracting capital necessary to support the utility's financial needs, thus minimizing the utility's cost of capital. TXU referred to Commission Rule §7.5414 and argued that actual expenditures for advertising will be allowed as a cost of service item of ratemaking purposes. TXU concluded that the costs associated with Activity/Project 21820000 are reasonable and necessary and should be included in TXU Gas' cost of service.

ACC's Position

ACC advocated that these costs should be disallowed. ACC stated that this project may benefit TXU shareholders, but captive TXU Gas customers already know their gas utility. This project provided no benefit to TXU Gas customers. None of the costs assigned by TXU Business Services to TXU Gas (Distribution or Pipeline) should be passed to TXU Gas customers. ACC recommended the following adjustment to remove non-recoverable expense:

Distribution:	($257,102)
Pipeline:	-0-

Dallas's Position

TXU Gas requested $257,102 for expense associated with the TXU Corporation brand name for Distribution in Project 21820000 "to generate awareness of corporate identity and brand." Dallas argued that there is no legitimate reason for regulated gas utility customers to pay hundreds of thousands of dollars for TXU Corporation to generate awareness for its identity. Dallas argued that this is an inappropriate expense for regulated customers to pay.

Dallas argued that Commission Rule §7.5414 provides for the inclusion of up to one-half of 1 percent of gross receipts of the utility, with certain exceptions. The key concept is that an advertising expense must be utility related and not lobbying, social membership, contributions, etc. The requested amount does not fall into the allowable categories because it is not advertising for Distribution. Rather, it is advertising for a non-utility entity. Dallas argued that this is a contribution or donation to TXU Corporation.

Dallas recommend that the full amount be eliminated from the utility's cost of service, resulting in a reduction of Distribution's expense request of $257,102.[339]

Examiners' Recommendation

The Examiners recommend the Commission deny the entire amount of $257,102 for Project 21820000, TXU Brand/Corporate.

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[339] Dallas Exhibit 1, Schedule JP-4 at 1.

The Examiners considered 16 TEX. ADMIN. CODE §7.5414 (2002) and recognize that the Commission may allow expenditures for advertising to be included in a cost of service, that do not exceed one-half of one percent of the gross receipts of the utility for utility services rendered in the public. TXU did not meet its burden to show that its expenditure is reasonable and necessary for the provision of gas utility service to the regulated gas utility customer.

The Examiners' recommendation is consistent with the Commission's rules because the exceptions articulated in 16 TEX. ADMIN. CODE §7.5414 that allow for such expenditures are not to generate awareness of corporate identity and brand. Instead, information relating to conservation of natural gas, reduction of natural gas during peak demand, advertising required by law or relating to service interruptions, safety measures, emergency conditions, employment opportunities, proposed rate schedules, or notifications of hearings are all directly applicable to the gas consumer and provision of gas utility service.

Although the facts of the case are distinguishable, the reasoning of the Examiners' recommendation in this proceeding is consistent with prior Commission decision in GUD 8976. In both instances, the utility failed to provide probative evidence showing that these advertising costs are reasonable and necessary for provision of service to gas utility customers.

42100000 Desktop

Support for the business computers, mainframe terminals, and peripheral equipment on the desktop.

TXU:

TXU requested Commission approval of $1,288,003 for Distribution and $847,066 for Pipeline, for inclusion in the rates paid by TXU Gas customers. TXU argued that ACC used a time period two years prior to the test year because the result was lower than if 2001 was used. TXU stated that Activity/Project 42100000 expense is assigned based on the actual number of desktop units and attendant devices supported for each TXU entity. The amount billed to each of the various TXU entities for services provided through Activity/Project 42100000 in 2002, including Distribution, was based on the number of desktop devices that each TXU entity had in 2002.

TXU explained that the increase in total expenses for Activity/Project 42100000 in 2002, as compared to prior years, was primarily due to increased staffing levels and lease costs associated with an expanding desktop environment. In periods prior to 2002, numerous employees who provided Distribution with services were assigned to TXU Electric Distribution (now Oncor Electric Delivery) and the expenses associated with these devices were charged to TXU Electric Distribution and then subsequently billed to TXU Gas - Distribution. In 2002, many of these same employees were assigned within TXU Gas - Distribution. In turn, their desktop devices are the direct responsibility of Distribution and the expenses associated with these devices are appropriately charged to Distribution.

TXU noted that of the $1,288,003 billed to Distribution for Activity/Project 42100000 during 2002, $304,114 was either capitalized or charged to stores overhead expenses and not included in Distribution's request. Therefore, in addition to being substantively incorrect, ACC's proposed disallowance amount is incorrect, as well. Those Activity/Project 42100000 expenses reflected in Distribution's cost of service are reasonable, necessary, and reflect a normalized level of expense for this service. ACC provided no evidence to the contrary and ACC's proposed disallowance should be rejected.

ACC's Position
ACC observed that total expenses increased from approximately $12.4 million in 1999 to $19.4 million in 2002, reflecting a 56 percent increase in three years. At the same time, the amount allocated to Distribution increased by 187 percent. ACC compared the test year 2002 allocation factor with prior years' allocations for the same activity. ACC observed that either an allocation factor changed appreciably during the test year, or the allocation factor to Distribution or Pipeline was incorrect. ACC assigned a revised allocation factor based on the prior years' allocations to yield a more equitable assignment of costs. ACC recommended that the 2000 Distribution allocation of 4.96 percent be applied to the test year total of $19,369,639 for allocated expenses of $960,734. ACC recommended the following adjustment to derive an allocation-adjusted expense:

Distribution: ($327,269)
Pipeline: -0-

Examiners' Recommendation
The Examiners find that TXU's evidence is vague and inconclusive regarding expenses for business computers, mainframe terminals, and peripheral equipment on the desktop. The Examiners find that TXU's request was not supported by the evidence provided in TXU Exhibit 15, Attachment SNR-2. That exhibit indicated TXU's request for expenses in the amounts of $1,288,003 for Distribution and $847,066 for Pipeline. After Intervening Parties challenged TXU's expense requests, TXU responded that of the $1,288,003 billed to Distribution for Activity/Project 42100000 during 2002, $304,114 was either capitalized or charged to stores overhead expenses and not included in Distribution's request.

The Examiners find that TXU's expense request for Project 42100000, Desktop, was actually $983,919 ($1,288,003 - $304,114 = $983,919) for Distribution and $847,066 for Pipeline. The Examiners find that ACC's allocation factor was appropriate, but was applied to the higher, incorrect amount. Applying ACC's ratio of 25.40843 percent to the revised amount (327,269 ÷ 1,288,033 = 25.40843 percent) results in a new adjustment value of $249,998 ($983,919 x 25.41 percent = $249,998). Therefore, the Examiners recommend that the Commission approve an expense adjustment of ($249,998), and approve $733,921 ($983,919 - $249,998 = $733,921) as Distribution expense. The Examiners recommend that the Commission approve the requested Pipeline cost of $847,066.

42200000 Telephone
Expenses for basic telephone service, equipment, PBX, handsets, maintenance, local and long distance service, phone network, and moves and changes.

TXU's Position
TXU requested Commission approval of $668,925 for Distribution and $506,418 for Pipeline, for inclusion in the rates paid by TXU Gas customers. TXU argued that ACC used 2001 as the "normalized" year because it results in a lower percentage to apply to test year levels. TXU stated that Activity/Project 42200000 is assigned based on the actual telephone service utilized. Therefore, the pro rata share of expenses a TXU entity receives is dependent on the level of telephone service that TXU entity has received. The amount billed to each of the various TXU entities for services provided through

Activity/Project 42200000 in 2002, including to Distribution, was based on the level of telephone service received by each TXU entity in 2002.

TXU explained why the increased pro rata share of expense assigned to Distribution in 2002 were higher than in 2001. In periods prior to 2002, numerous employees who provided Distribution services resided in TXU Electric Distribution (now Oncor Electric Delivery) and the expenses associated with Activity/Project 42200000 were charged to TXU Electric Distribution and then subsequently billed to Distribution. In 2002, many of these same employees resided within TXU Gas - Distribution. In turn, their telephone devices and associated costs are the direct responsibility of Distribution, and the expenses associated with these devices were appropriately charged to Distribution.

TXU noted that of the $668,925 billed to Distribution for Activity/Project 42200000 during 2002, $187,600 was either capitalized or charged to stores overhead expenses and not included in Distribution's request. Therefore, in addition to being substantively incorrect, ACC's proposed disallowance of $243,518 for Distribution is incorrect, as well. TXU argued the Activity/Project 42200000 expenses reflected in Distribution's cost of service are reasonable, necessary, and reflect a normalized level of expense for this service.

ACC:
ACC stated that total expenses remained relatively flat between 1999 and 2002, but the allocation to Distribution more than doubled from 3.7 percent to 8.1 percent. ACC recommended that the 2001 Distribution allocation of 5.14 percent be applied to the test year total of $8,276,406 for allocated Distribution expenses of $425,407.

ACC compared the test year 2002 allocation factor with prior years' allocations for the same activity. ACC observed that either an allocation factor changed appreciably during the test year, or the allocation factor to Distribution or Pipeline was incorrect. ACC assigned a revised allocation factor based on the prior years' allocations to yield a more equitable assignment of costs. ACC recommended the following adjustment to derive an allocation adjusted expense:

Distribution:	($243,518)
Pipeline:	-0-

Examiners' Recommendation
The Examiners find that TXU's evidence is vague and inconclusive regarding expenses for basic telephone service, equipment, PBX, handsets, maintenance, local and long distance service, phone network, and moves and changes. The Examiners find that the amount TXU requested was not supported by the evidence provided in TXU Exhibit 15, Attachment SNR-2. That exhibit indicated TXU's request for expenses in the amounts of $668,925 for Distribution and $506,418 for Pipeline. After Intervening Parties challenged TXU's expense requests, TXU responded that of the $668,925 billed to Distribution for Activity/Project 42200000 during 2002, $187,600 was either capitalized or charged to stores overhead expenses and not included in Distribution's request.

The Examiners find that TXU's expense request for Project 42200000, Telephone, was actually $481,325 ($668,925 -$187,600 = $481,325) for Distribution and $506,418 for Pipeline. The Examiners find that ACC's allocation factor was appropriate, but was applied to the higher, incorrect amount. Applying ACC's ratio of 36.40438 percent (243,518 ÷ 668,925 = 36.40 percent) to the revised amount results in a new adjustment value of $175,223 ($481,325 x 36.40438 percent = $175,223). Therefore, the Examiners recommend that the Commission approve an expense adjustment of ($175,223) and an expense amount of $306,102 ($481,325 - $152,289 = $306,102) for Distribution. The Examiners recommend that the Commission approve the requested Pipeline expense of $506,418.

42300000 Data Network

Expenses for access to end usage of the area-wide network.

TXU's Position

TXU requested Commission approval of $673,023 for Distribution and $453,491 for Pipeline, for inclusion in the rates paid by TXU Gas customers. TXU argued that ACC altered its normalization approach. To get the desired result ACC averaged three years of the pro rata share that Distribution received for the services provided through Activity/Project 42300000 which is assigned to TXU entities based on their access to end usage of the TXU Wide Area Network. In periods prior to 2002, numerous employees who provided Distribution services resided in TXU Electric Distribution (now Oncor Electric Delivery). The expenses associated with Activity/Project 42300000 were charged to TXU Electric Distribution and subsequently billed to TXU Gas - Distribution. In 2002, many of these same employees resided within Distribution. In turn, their costs associated with the use of TXU's Wide Area Network are the direct responsibility of Distribution, and the expenses associated with this service are appropriately charged to Distribution.

TXU noted that of the $673,023 billed to Distribution for Activity/Project 42300000 during 2002, $178,030 was either capitalized or charged to stores overhead expenses and not included in Distribution's request. Therefore, in addition to being substantively incorrect, ACC's proposed disallowance amount of $135,291 for Distribution was incorrect as well. TXU argued the Activity/Project 42300000 expenses reflected in Distribution's cost of service are reasonable, necessary, and reflect a normalized level of expense for this service.

ACC's Position

ACC noted that total expenses remained relatively flat between 2000 and 2002, but the allocation to Distribution increased from 3.6 percent to 5.8 percent, a 61 percent change. The average over the three-year period is 4.62 percent. ACC recommended that the average Distribution allocation factor be applied to the test year total expense of $11,630,846 for allocated Distribution expenses of $537,733.

ACC compared the test year 2002 allocation factor with prior years' allocations for the same activity. ACC observed that either an allocation factor changed appreciably during the test year, or the allocation factor to Distribution or Pipeline was incorrect. ACC assigned a revised allocation factor based on the prior years' allocations to yield a more equitable assignment of costs. ACC recommended the following adjustment to derive an allocation adjusted expense:

Distribution: ($135,291)
Pipeline: -0-

Examiners' Recommendation

The Examiners find that the amount TXU requested was not supported by the evidence provided in TXU Exhibit 15, Attachment SNR-2. That exhibit indicated TXU's request for expenses in the amounts of $673,023 for Distribution and $453,491 for Pipeline. After Intervening Parties challenged TXU's expense requests, TXU responded that of the $673,023 billed to Distribution for Activity/Project 42300000 during 2002, $178,030 was either capitalized or charged to stores overhead expenses and not included in Distribution's request.

The Examiners find that TXU's expense request for Project 42300000, Data network, was actually $494,993 ($673,023 - $178,030 = $494,993) for Distribution and $453,491 for Pipeline. The Examiners find that ACC's allocation factor was appropriate, but was applied to the higher, incorrect amount. Applying ACC's ratio of 20.10198 percent to the revised amount (135,291 ÷ 673,023 = 20.10198 percent) results in a new adjustment value of $99,503 ($494,993 x 20.10198 percent = $99,503). Therefore, the Examiners recommend that the Commission approve an expense adjustment of ($99,503), and approve $395,490 ($494,993 - $99,503 = $395,490) as Distribution expense. The Examiners recommend that the Commission approve the requested Pipeline cost of $453,491.

42400000 Radio

Expenses related to day-to-day services and support of the TXU 896 field radio system.

TXU's Position

TXU requested Commission approval of $1,299,507 for Distribution and $451,375 for Pipeline, for inclusion in the rates paid by TXU Gas customers. TXU stated that Activity/Project 42400000 is assigned to TXU entities based on the number of 896 radios used by a TXU entity. Various TXU entities use the radios to provide both voice and data communications to and from field services functions. Subsequent to the merger with Pipeline, TXU Gas - Distribution began using 896 radios to facilitate its various service functions. Use of the radios in Distribution's operations has been increasing since the merger.

TXU argued that prior to 2002, much of the field services organization that supports Distribution operations resided in TXU Electric Distribution (now Oncor Electric Delivery). During that time, TXU Electric Distribution billed TXU Gas - Distribution for the services performed based on time tracking. Those costs included the costs associated with 896 radios. In 2002, most of these same field organizations resided within TXU Gas - Distribution. In turn, the 896 radios, and their associated costs, are the direct responsibility of Distribution.

TXU noted that of the $1,299,597 billed to Distribution for Activity/Project 42400000 during 2002, $379,314 was either capitalized or charged to stores overhead expenses and not included in Distribution's request. Therefore, in addition to being substantively incorrect, ACC's proposed disallowance amount of $712,456 for Distribution is incorrect, as well. TXU argued that the Activity/Project 42400000 expenses reflected in Distribution's cost of service are reasonable, necessary, and reflect a normalized level of expense for this service.

ACC 's Position

ACC compared the test year 2002 allocation factor with prior years' allocations for the same activity. ACC observed that either an allocation factor changed appreciably during the test year, or the allocation factor to Distribution or Pipeline was incorrect. ACC assigned a revised allocation factor based on the prior years' allocations to yield a more equitable assignment of costs.

ACC noted that total expenses remained relatively flat between 2000 and 2002, but the allocation to Distribution more than doubled between 2001 and 2002, from 5.1 percent to 11.4 percent. ACC recommended that the 2001 Distribution allocation of 5.14 percent be applied to the test year total of $11,422,982 for allocated Distribution expenses of $587,141. ACC recommended the following adjustment to derive an allocation adjusted expense:

Distribution: ($712,456)
Pipeline: -0-

Examiners' Recommendation

The Examiners find TXU's evidence to be vague and inconclusive regarding expenses for access to end usage of the area-wide network. The Examiners find that the amount TXU requested was not supported by the evidence provided in TXU Exhibit 15, Attachment SNR-2. That exhibit indicated TXU's request for expenses in the amounts of $1,299,507 for Distribution and $451,375 for Pipeline. After Intervening Parties challenged TXU's expense requests, TXU responded that of the $1,299,507 billed to Distribution for Activity/Project 42400000 during 2002, $379,314 was either capitalized or charged to stores overhead expenses and not included in Distribution's request.

The Examiners find that TXU's expense request for Project 42400000, Radio, was actually $920,193 ($1,299,507- $379,314= $920,193) for Distribution and $451,375 for Pipeline. The Examiners find that ACC's allocation factor was appropriate, but was applied to the higher, incorrect amount. Applying ACC's ratio of 54.82509 ($712,456 ÷ $1,299,507 = 54.82509 percent) to the revised amount results in a new adjustment value of $504,497 ($920,193 x 54.82509 percent = $504,497). Therefore, the Examiners recommend that the Commission approve an expense adjustment of ($504,497) and approve $415,626 ($920,123 - $504,497= $415,626) as Distribution expense. The Examiners recommend that the Commission approve the requested Pipeline cost of $451,375.

42500000 App Port-MF Application

Expenses for mainframe and client/server system applications, including processor, storage, software, application maintenance, and staff.

TXU's Position

TXU requested Commission approval of $163,043 for Distribution and $103,437 for Pipeline, for inclusion in the rates paid by TXU Gas customers. TXU explained that Activity/Project 42500000 is assigned to TXU entities based on the mainframe storage capacity and mainframe processing time used by a TXU entity. Many legacy software applications utilized by Distribution continue to be hosted on the mainframe. The amount billed to Distribution for the services provided through Activity/Project 42500000 reflected the actual use of this service for 2002.

TXU disagreed with ACC's position that the increase in desktop expense in Project 42100000 - Desktop should offset the mainframe expense because it would reduce reliance on mainframe applications. TXU argued that ACC's argument was erroneous and had no fact basis. Rather, TXU explained, the desktop environment is used to access the mainframe. The two are not mutually exclusive.

TXU noted that of the $163,043 billed to Distribution for Activity/Project 42500000 during 2002, $40,510 was either capitalized or charged to stores overhead expenses and not included in Distribution's request. Therefore, in addition to being substantively incorrect, ACC's proposed disallowance amount of $73,911 for Distribution is incorrect, as well. TXU argued that the Activity/Project 42500000 expenses reflected in Distribution's cost of service are reasonable, necessary, and reflect a normalized level of expense for this service.

ACC's Position

ACC compared the test year 2002 allocation factor with prior years' allocations for the same activity. ACC observed that either an allocation factor changed appreciably during the test year, or the allocation factor to Distribution or Pipeline was incorrect. ACC assigned a revised allocation factor based on the prior years' allocations to yield a more equitable assignment of costs.

ACC noted that total expenses remained relatively flat between 2000 and 2002, but the allocation to Distribution almost doubled between 2001 and 2002, from 0.6 percent to 1.1 percent. ACC recommended that the 2001 Distribution allocation of 0.62 percent be applied to the test year total of $14,376,054 for allocated Distribution expenses of $89,132. ACC recommended the following adjustment to derive an allocation adjusted expense:

Distribution: ($73,911)
Pipeline: -0-

Examiners' Recommendation

The Examiners find TXU's presentation of the evidence to be vague and inconclusive with respect to mainframe and client/server system applications, including processor, storage, software, application maintenance. The Examiners find that the amount TXU requested was not supported by the evidence provided in TXU Exhibit 15, Attachment SNR-2. That exhibit indicated TXU's request for expenses in the amounts of $163,043 for Distribution and $103,437 for Pipeline. After Intervening Parties challenged TXU's expense requests, TXU responded that of the $163,043 billed to Distribution for Activity/Project 42500000 during 2002, $40,510 was either capitalized or charged to stores overhead expenses and not included in Distribution's request.

The Examiners find that TXU's expense request for Project 42500000, App Port - MF Application, was actually $122,533 ($163,043 - $40,510 = $122,533) for Distribution and $103,437 for Pipeline. The Examiners find that ACC's allocation factor was appropriate, but was applied to the higher, incorrect amount. Applying ACC's ratio of 45.33221 percent ($73,911 ÷ $163,043 = 45.33221 percent) to the revised amount results in a new adjustment value of $55,547 ($122,533 x 45.33221 percent = $55,547). Therefore, the Examiners recommend that the Commission approve an expense adjustment of ($55,547) and approve $415,626 ($122,533 - $55,547 = $66,986) as Distribution expense. The Examiners recommend that the Commission approve the requested Pipeline cost of $103,437.

42700000 APP-Port-Client Server

Expenses for mainframe and client/server system applications.

TXU's Position

TXU requested Commission approval of $1,692,509 for Distribution and $842,608 for Pipeline, for inclusion in the rates paid by TXU Gas customers. TXU argued that ACC's recommendation to disallow a portion of the Distribution and Pipeline costs in this account should be denied. TXU stated that TXU entities, including Distribution and Pipeline, have increased use of client servers for new software applications and are not compatible with mainframe technology. The cost for leasing the servers and the labor and labor-related costs associated with supporting these software applications are reasonable, necessary, and are ongoing. Therefore, TXU argued, the full amount of Distribution's and Pipeline's 2002 expenses associated with Activity/Project 42700000 should be included in their respective cost of service requests. TXU noted that of the $1,692,509 billed to Distribution for Activity/Project 42700000 during 2002, $369,989 was either capitalized or charged to stores overhead expenses and not included in Distribution's request.

ACC's Position

ACC stated that this project showed an extraordinary level of expense in 2002 that was not representative of ongoing expenses. ACC based its adjustment upon a comparison of the test year allocated expense with prior years' expenses for the same activity. ACC observed that the project may have represented an ongoing activity, but that the test year amount was anomalously high compared to past years. ACC adjusted the test year costs to reflect a more likely level of expense based on historic expenses.

ACC noted that the total expenses under this project increased by 34 percent from 2000 to 2001, and jumped more than 3.5 times between 2001 and 2002, from $10.0 million to $13.4 million to $49.1 million. Expenses allocated to Distribution increased by more than 60 percent between 2000 and 2002, while expenses allocated to Pipeline increased from $77,242 in 2000 to $228,428 in 2001 to $842,608 in 2002. ACC recommended that the Distribution and Pipeline adjusted test year expenses be limited to the 2001 amounts of $1,329,731 and $228,428 respectively. ACC recommended the following adjustments to derive cost-adjusted expenses:

Distribution: ($362,777)
Pipeline: ($614,179)

Examiners' Recommendation

The Examiners did not find TXU's evidence probative that the costs were reasonable. Statements affirming that the money was spent or spent on labor-related costs for supporting the software applications fail to explain why the requested level of cost was reasonable and necessary; why additional labor was necessary; or why there were significant increased costs. Because the evidence presented by TXU failed to show that the costs were necessary and were reasonable, the Examiners recommend partial disallowance in accordance with ACC's proposal. It is reasonable for the Commission to adjust TXU's request and allow Distribution expense of $1,329,732 ($1,692,509 requested - $362,777 adjustment = $1,329,732). It is also reasonable for the Commission to adjust TXU's request and allow Pipeline expense of $228,429 ($842,608 requested - $614,179 adjustment = $228,429).

42800000 Staff Support

Expenses associated with IT project related consultants.

TXU's Position

TXU requested Commission approval of $78,972 for Distribution and $17,073 for Pipeline, for inclusion in the rates paid by TXU Gas customers. TXU stated that Activity/Project 42800000 is billed to TXU entities based on time tracking. Therefore, the expenses billed to both Distribution and Pipeline represent the actual level of service provided to each TXU entity for the test year period. TXU argued that ACC's proposed disallowance of a portion of these costs should be denied. TXU noted that of the $78,972 billed to Distribution during 2002, $8,375 was either capitalized or charged to stores overhead expenses and not included in Distribution's request. TXU argued that ACC's proposed disallowance amount of $36,946 for TXU Gas - Distribution is also incorrect.

ACC's Position

ACC observed that the total expenses actually declined between 2001 and 2002, but the amounts allocated to Distribution and Pipeline almost doubled between 2001 and 2002. ACC stated that this project showed an extraordinary level of expense in 2002 that was not representative of ongoing expenses. ACC recommended that the 2001 allocated amounts of $42,026 for Distribution and $11,264 for Pipeline be used as the adjusted test year amounts. ACC based its adjustment upon a comparison of the test year allocated expense with prior years' expenses for the same activity. ACC observed that the project may have represented an ongoing activity, but that the test year amount was anomalously high compared to past years. ACC adjusted the test year costs to reflect a more likely level of expense based on historic expenses. ACC recommended the following adjustments to derive cost-adjusted expenses:

Distribution: ($36,946)
Pipeline: ($5,809)

Examiners' Recommendation

TXU's evidence is not probative of the reasonableness of expenses associated with IT project related consultants. TXU's statements that the bills for services represent the actual level of service provided by TXU Business Services to each TXU entity and that services were billed based on time tracking do not demonstrate that the amounts were both necessary and reasonable. TXU failed to explain why the staff support was necessary for IT project related consultants and why the requested cost was reasonable and necessary. Because the evidence presented by TXU failed to show that the costs were both necessary and reasonable, the Examiners recommend partial disallowance in accordance with ACC's proposal. It is reasonable for the Commission to adjust TXU's request and allow Distribution expense of $42,030 ($78,972 requested - $36,946 adjustment = $42,030). It is also reasonable for the Commission to adjust TXU's request and allow Pipeline expense of $11,264 ($17,073 requested - $5,809 adjustment = $11,264).

42804000 Staff Support-Service Coordinator

Services associated with identification and coordination of emerging issues, and supporting executive management in developing goals and strategies.

TXU's Position

TXU requested Commission approval of $80,648 for Distribution and $53,877 for Pipeline, for inclusion in the rates paid by TXU Gas customers. TXU stated that Activity/Project 42804000 is billed to TXU entities based on time tracking. Therefore, the expenses billed to both Distribution and Pipeline represent the actual level of service provided to each TXU entity for the test year period. TXU argued that ACC's proposed disallowance of a portion of these costs should be denied. TXU noted that of the $80,648 billed to TXU Gas - Distribution for Activity/Project 42804000 during 2002, $20,619 was either capitalized or charged to stores overhead expenses and not included in TXU Gas - Distribution's request. TXU argued that ACC's Expenses associated with IT project related consultants proposed disallowance amount of $31,860 for TXU Gas - Distribution is also incorrect.

ACC's Position

ACC calculated that the total expenses under this project increased 72 percent between 2001 and 2002, from $1.0 million to $1.7 million. Similarly, expenses allocated to Distribution increased from $48,788 to $80,648, or 65 percent, over the same period. ACC recommended that the adjusted test year for Distribution be limited to the 2001 amount of $48,788. ACC stated that this project showed an extraordinary level of expense in 2002 that was not representative of ongoing expenses. ACC based its adjustment upon a comparison of the test year allocated expense with prior years' expenses for the same activity. ACC observed that the project may have represented an ongoing activity, but that the test year amount was anomalously high compared to past years. ACC adjusted the test year costs to reflect a more likely level of expense based on historic expenses. ACC recommended the following adjustment to derive a cost adjusted expense:

Distribution: ($31,860)
Pipeline: -0-

Examiners' Recommendation

TXU's evidence regarding how the services in this category are billed does not demonstrate that the amount was necessary or reasonable. TXU fails to explain how or why the costs for identification and coordination of emerging issues and the support of executive management in development of goals and strategies is necessary for the provision of gas service to TXU's gas customers. The Examiners recommend partial disallowance in accordance with ACC's proposal. It is reasonable for the Commission to adjust TXU's request by ($31,860) for Distribution.

42900000 I/T Management & Administration

Includes management & administration expenses, including office of the vice president, business support services, accounting support, and technical support.

TXU's Position

TXU requested Commission approval of $372,100 for Distribution and $200,730 for Pipeline, for inclusion in the rates paid by TXU Gas customers. TXU explained that expenses for Activity/Project 42900000 are assigned to TXU entities based on the planned spending Information Technology spending ratios for each TXU entity. TXU stated that the increased pro rata share of total Information Technology expense experienced by TXU Gas - Distribution over the past few years primarily resulted because Information Technology expenses that once were billed to TXU Electric Distribution (now Oncor Electric Delivery), and then subsequently billed to Distribution, are now billed directly to Distribution. Therefore, Distribution's Information Technology spending ratios increased, compared to prior years. TXU argued that this is not actually an increase in costs, but a change in the way these costs are captured and recorded on the books of TXU Gas - Distribution. TXU also noted that of the $372,100 billed to Distribution for Activity/Project 42900000 during 2002, $97,338 was either capitalized or charged to stores overhead expenses and not included in Distribution's request. Therefore, TXU argued, in addition to being substantively incorrect, ACC's proposed disallowance amount of $63,175 was incorrect.

ACC's Position

ACC observed that total expenses remained relatively flat between 1999 and 2002, but the allocation to Distribution increased almost 50 percent, from 3.6 percent to 5.3 percent between 2000 and 2002. The average allocation for each year of the three-year period is 4.37 percent. ACC compared the test year 2002 allocation factor with prior years' allocations for the same activity. ACC observed that either an allocation factor changed appreciably during the test year, or the allocation factor to Distribution or Pipeline was incorrect. ACC assigned a revised allocation factor based on the prior years' allocations to yield a more equitable assignment of costs. ACC recommended the following adjustment as an allocation adjusted expense: ACC recommended that the average Distribution allocation factor be applied to the test year total expense of $7,069,259 to derive an allocated Distribution expense of $308,927. Thus, ACC recommended the following adjustment to TXU's request:

Distribution: ($63,173)
Pipeline: -0-

Examiners' Recommendation
TXU's evidence is vague and inconclusive regarding management and administration expenses, including office of the vice president, business support services, accounting support, and technical support. The Examiners find that the amount TXU requested was not supported by the evidence provided in TXU Exhibit 15, Attachment SNR-2. That exhibit indicated TXU's request for expenses in the amounts of $372,100 for Distribution and $200,730 for Pipeline. After Intervening Parties challenged TXU's expense requests, TXU responded that of the $372,100 billed to Distribution for Activity/Project 42900000 during 2002, $97,338 was either capitalized or charged to stores overhead expenses and not included in Distribution's request.

The Examiners find that TXU's expense request for Project 42900000, IT Management and Administration, was actually $229,762 ($327,100 - $97,338 = $229,762) for Distribution and $200,730 for Pipeline. The Examiners find that ACC's allocation factor was appropriate, but was applied to the higher, incorrect amount. Applying ACC's ratio of 16.97742 percent ($63,173 ÷ $372,100 = 16.97742 percent) to the revised amount results in a new adjustment value of $39,008 ($229,762 x 16.97742 percent = $39,008). Therefore, the Examiners recommend that the Commission approve an expense adjustment of ($39,008) and approve $190,754 ($229,762 - $39,008 = $190,754) as Distribution expense. The Examiners recommend that the Commission approve the requested Pipeline cost of $200,730.

43000000 Technical Planning, EIA, Chargeback, & Corp. Overhead
Expenses for TXU system-wide initiatives, IT product testing and evaluation, IT strategic planning, and Business Services corporate overhead assigned to the I/T, human resources, and administrative services departments.

TXU's Position
TXU requested Commission approval of $835,681 for Distribution and $450,719 for Pipeline, for inclusion in the rates paid by TXU Gas customers. TXU rejected ACC's proposal to disallow a portion of these requested amounts, claiming that ACC provided no basis other than that costs rose in 2002 compared to 2001. TXU noted that of the $835,681 billed to Distribution during 2002, $220,842 was either capitalized or charged to stores overhead expenses and not included in Distribution's request. ACC's proposal is substantively incorrect, and ACC's proposed disallowance of $350,266 for Distribution is incorrect, as well.

TXU stated that a portion of the expenses included in Activity/Project 43000000 for the test year consisted of Information Technology's prior years' sales and use tax adjustment. TXU excluded these prior years' sales and use amounts from its proposed cost of service. Therefore, Distribution's and Pipeline's test year cost of service amounts were reduced by $109,130 and $64,252, respectively, to reflect the elimination of prior years' sales and use tax.

TXU stated that Dallas's data are outdated and contained no evidence that the amounts requested by the utility were not reasonable. TXU also disagreed with Dallas's proposed adjustment that was based upon an average of the test year, the GUD 9313 test year (ending September 30, 2001), and the PUC Docket No. 22350 test year (ending September 30, 1999). TXU stated that Dallas's approach was an example of more extreme piecemeal ratemaking. TXU argued that Dallas presented no evidence to support its position.

ACC's Position

ACC noted that total expenses nearly tripled between 2000 and 2002, climbing from $5.3 million to $15.4 million. At the same time, expenses allocated to Distribution quadrupled over the same period. ACC recommended that the adjusted test year be limited to the 2001 amount of $485,415 for Distribution.

ACC stated that this project showed an extraordinary level of expense in 2002 that was not representative of ongoing expenses. ACC based its adjustment upon a comparison of the test year allocated expense with prior years' expenses for the same activity. ACC observed that the project may have represented an ongoing activity, but that the test year amount was anomalously high compared to past years. ACC adjusted the test year costs to reflect a more likely level of expense based on historic expenses. ACC recommended the following adjustment to derive cost-adjusted expense:

Distribution:	($350,266)
Pipeline:	-0-

Dallas's Position

Dallas observed that a total of $835,681 and $450,719 of Project 43000000 costs were assigned to Distribution and Pipeline, respectively. Dallas presumed that a portion of the costs was capitalized so that the expense levels reflected in the revenue requirement were $619,374 and $385,016 for Distribution and Pipeline, respectively.

Dallas reviewed the allocation percentage for Distribution and Pipeline proposed in GUD 9400, in GUD 9313, and in the PUC Docket No. 23350 UCOS filing; decided the proposed costs were excessive; and recommended an adjustment to reflect an appropriate, normalized expense level. Dallas noted that TXU assigned costs on an annual basis, based on "planned spending ratios."

Dallas calculated that the cost proposed in GUD 9400 to Distribution was forty-seven percent higher than it was in GUD 9313. The current allocation percentage to Distribution is approximately nineteen percent higher than the average for the three rate case test years. The situation is even more skewed for Pipeline. The test year allocation percentage for Pipeline is a full 100 percent higher than the allocable relationship proposed in GUD 9313. However, based on the average of the three selected test years, Dallas concluded that the current allocation percentage is approximately twenty percent greater than the average. The result, as recommended by Dallas is a $96,885 reduction to Distribution revenue requirements and a $65,162 reduction for Pipeline.[340]

Examiners' Recommendation

TXU's evidence is vague and inconclusive regarding expenses for TXU system-wide initiatives, IT product testing and evaluation, IT strategic planning, and Business Services corporate overhead assigned to the I/T,

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[340] Dallas Exhibit 1, Schedule JP-4 at 8 of 8.

human resources, and administrative services departments. The amount TXU requested was not supported by the evidence provided in TXU Exhibit 15, Attachment SNR-2. That exhibit indicated TXU's request for expenses in the amounts of $835,681 for Distribution and $450,719 for Pipeline. After Intervening Parties challenged TXU's expense requests, TXU responded that of the $835,681 billed to Distribution for Activity/Project 43000000 during 2002, $220,842 was either capitalized or charged to stores overhead expenses and not included in Distribution's request.

The Examiners find that TXU's expense request for Project 43000000 (Technical Planning, EIA, Chargeback, & Corporate Overhead), was actually $614,839 ($835,681 - $220,842 = $614,839) for Distribution and $450,719 for Pipeline. The Examiners find that ACC's allocation factor was appropriate, but was applied to the higher, incorrect amount. Applying ACC's ratio of 41.91384 percent ($350,266 ÷ $835,681 = 41.91384 percent) to the revised amount results in a new adjustment value of $257,703 ($614,839 x 41.91384 percent = $257,703). Therefore, the Examiners recommend that the Commission approve an expense adjustment of ($257,703) and approve $357,135 ($614,838 - $257,703 = $357,135) as Distribution expense. The Examiners recommend that the Commission approve the requested Pipeline cost of $200,842.

43200000 Account Team Management

Expenses associated with account team management.

TXU's Position

TXU requested Commission approval of $111,781 for Pipeline, for inclusion in the rates paid by TXU Gas customers. TXU described that Activity/Project 43200000 is assigned to TXU entities based on the full time equivalent labor dedicated to each TXU entity. The amount of expense billed to TXU Gas - Pipeline during 2002 reflected the actual cost of performing this service on behalf of this entity in 2002 and is the best representation of the ongoing level of service required by TXU Gas-Pipeline. TXU argued that the Activity/Project 43200000 expenses reflected in TXU Gas-Pipeline's cost of service are reasonable, necessary, and reflect a normalized level of expense for this service.

ACC's Position

ACC argued that the description of this project offered by TXU provided too little information for appropriate evaluation of the necessity of the activity. However, due to the Pipeline allocation factor more than doubling between 2001 and 2002, from 6.7 percent to 14.8 percent, ACC recommended that the 2001 allocation factor be applied to the test year amount of $757,776. Thus, the adjusted test year expense would be $50,468.

ACC compared the test year 2002 allocation factor with prior years' allocations for the same activity. ACC observed that either an allocation factor changed appreciably during the test year, or the allocation factor to Distribution or Pipeline was incorrect. ACC assigned a revised allocation factor based on the prior years' allocations to yield a more equitable assignment of costs. ACC recommended the following adjustment to derive an allocation adjusted expense:

Distribution: -0-
Pipeline: ($61,237)

Examiners' Recommendation

TXU's explanation of the manner in which Business Services bills TXU Gas, or stating that the costs are reasonable, is not sufficient to prove that the expenses are reasonable. The Examiners recommend, consistent with ACC's proposal, that the Commission adjust TXU's request and allow Pipeline expense of $50,544 ($111,781 requested - $61,237adjustment = $50,544).

50800000 Investor Relations

Services associated with informing the investment community of the state of the Corporation to facilitate full valuation, respond to investment community inquiries and communicate investor and analyst outlook to management.

TXU's Position

TXU requested Commission approval of $26,456 for Distribution and an additional $26,456 for Pipeline, for inclusion in the rates paid by TXU Gas customers. TXU claimed that Activity/Project 50800000 is assigned to TXU entities based on an assessment of dedicated resources to each TXU entity. Prior to 2002, methodology for Activity/Project 50800000 was based on net assets plus investments. In 2002, the methodology was changed to assessment of dedicated resources. The change was implemented for greater precision in billing Activity/Project 5080000 to the TXU entities for which investors demonstrated the greater need for information. The increase in the pro rata share of Activity/Project 5080000 billed to Distribution and Pipeline resulted from greater shareholder interest in the operations of these two entities. TXU argued that the Activity/Project 50800000 expenses reflected in Distribution's and Pipeline's cost of service amounts are reasonable, necessary, and reflect a normalized level of expense for this service.

ACC's Position

ACC argued that the Distribution allocation factor dropped from 0.59 percent to 0.48 percent between 2000 and 2001, yet almost tripled to 1.25 percent in 2002. Likewise, the Pipeline allocation factor dropped from 0.28 percent to 0.21 percent between 2000 and 2001, but increased to 1.25 percent in 2002. ACC recommended that the 2001 allocation factors be applied to the test year amount of $2,116,517, so that the adjusted test year Distribution expense is $10,159 and the Pipeline expense is $4,445.

ACC compared the test year 2002 allocation factor with prior years' allocations for the same activity. ACC observed that either an allocation factor changed appreciably during the test year, or the allocation factor to Distribution or Pipeline was incorrect. ACC assigned a revised allocation factor based on the prior years' allocations to yield a more equitable assignment of costs. ACC recommended the following adjustments to derive an allocation- adjusted expenses:

Distribution: ($16,297)
Pipeline: ($22,012)

Examiners' Recommendation

TXU's statements explaining how these services are billed or that the methodology of billing has changed is not sufficient to show the reasonableness and necessity of the requested amounts. The Examiners recommend that TXU receive no costs for Project 50800000, Investor Relations. This recommendation is consistent with the previous Commission decision in GUD 8976 in which the Commission denied TXU $3,070 for shareholder services and investor relations because TXU Pipeline has no investors; only TXU Corp. has outside investors and issues shares. TXU failed to prove that Investor Relations amounts of $26,456 for Distribution and an additional $26,456 for Pipeline are necessary and reasonable expenses in providing service to gas utility customers.

53900000 Tax Services

Expenses associated with the administration of various tax services and issues. Tax accounting expenses reflect accounting for all federal and state income and other taxes. This includes accounting information required for tax filing compliance.

TXU's Position

TXU requested Commission approval of $805,723 for Distribution and $690,619 for Pipeline, for inclusion in the rates paid by TXU Gas customers. TXU argued that Intervenors' assertion is incorrect that the services provided to Distribution and to Pipeline through Activities/Projects 53900000 for Tax Services and 60320000 for Corporate Tax Accounting are not pertinent to the utility's regulated tax expenses. TXU stated that the services provided through Activity/Project 53900000 include the administration of various tax services and issues such as state, federal, local, and international taxation. As part of these services, the Corporate Tax Department, among other responsibilities, researches tax issues, analyzes the impact of various tax laws, provides a liaison between the TXU entities it serves and the taxing authorities, and prepares various tax filings directly related to the assets, revenues, and expenses of Distribution and Pipeline. The Corporate Tax Department's performance of these services helps Distribution and Pipeline correctly report its taxable income used to calculate its regulated tax expense, thus benefitting all customers.

TXU claimed the services provided through Activity/Project 60320000 include accounting for all federal and state income and other taxes, furnishing accounting information required for tax filing compliance, and providing tax related regulatory support for regulated Business Units. As part of these services, the Tax Accounting Department ensures the proper tax accounting for all assets, revenues, and expenses of Distribution and Pipeline. The Tax Accounting Department's performance of these services ensures that Distribution's and Pipeline's tax expenses are appropriately captured and recorded for use by the Corporate Tax Department, in SEC filings, and by various regulatory bodies, including the Railroad Commission. TXU acknowledged that this Commission has established a precedent as to how regulated income taxes are to be established in a rate proceeding, but argued that such precedent was not intended to eliminate the inclusion of reasonable and necessary tax compliance or accounting expense from a utility's cost of service.

ACC's Position

ACC noted that total expenses increased 45 percent between 2001 and 2002, climbing from $7.9 million to $11.5 million. Meanwhile, expenses allocated to both Distribution and Pipeline doubled over the same period. ACC recommended that the adjusted test year be limited to the 2001 amounts of $397,980 for Distribution and $318,384 for Pipeline. ACC stated that this project showed an extraordinary level of expense in 2002 that was not representative of ongoing expenses. ACC based its adjustment upon a comparison of the test year allocated expense with prior years' expenses for the same activity. ACC observed that the project may have represented an ongoing activity, but that the test year amount was anomalously high compared to past years. ACC adjusted the test year costs to reflect a more likely level of expense based on historic expenses. ACC recommended the following adjustments to derive cost adjusted expenses:

Distribution: ($407,743)
Pipeline: ($322,236)

Dallas's Position

Dallas addressed Project 53900000 (Tax Services) and Project 60320000 (Corporate Tax Accounting) together. Dallas calculated that the sum of TXU's requests for these two projects was $1,014,760 for Distribution and $713,839 for Pipeline.[341] Dallas observed that the tax proposed by TXU is hypothetical and fails to account for the utility's income taxes on a consolidated basis. TXU did not provide to ratepayers any benefit that would result from the TXU Corp. filing of a consolidated tax return. Because the utility failed to provide the data needed for Commission consideration of a consolidated tax savings component, Dallas recommended that customers should not pay for any cost of preparing and investigating income taxes. TXU's hypothetical tax calculation used for ratemaking ignores the actual tax accounting and related analyses associated with the maintenance of detailed records for filing tax returns. Dallas recommended that the Tax Preparation Costs (Projects 53900000, 60320000) of $1,014,760 Distribution and $713,839 Pipeline be disallowed because ratepayers receive none of the benefits received by TXU for its consolidated return.[342]

Examiners' Recommendation

The Examiners' recommendations for project 53900000, Tax Services, and Project 60320000, Corporate Tax Accounting, are the same. The Examiners have reviewed the evidence for any information relating to TXU's consolidated tax benefits. Because TXU failed to present evidence regarding the savings it would enjoy as a result of its consolidated tax filing, the Examiners recommend that the Commission disallow all expenses associated with the administration of tax services or for accounting information required for tax filing compliance requested by TXU in Activity/Project 53900000, Tax Services.

This may be the first time this Commission has had an opportunity to address the use and treatment of consolidated tax savings. However, the Public Utility Commission (PUC) recently required TXU Corp. to derive a consolidated tax savings adjustment applicable to TXU Electric.[343]

Rather than filing individual tax returns for each subsidiary, a parent company, such as TXU Corp., will make a consolidated federal income tax return on behalf of it and its various subsidiaries. Consolidated tax savings are the amounts saved by a parent company's use of a consolidated federal income tax return. The consolidated tax filing results in annual consolidated taxable income for the parent company and subsidiaries that is in most instances less than the combined taxable incomes of the affiliated subsidiaries, with gains calculated on a stand alone basis.

By making a consolidated tax filing, the corporation is able to take all current losses against all current gains, thereby realizing the value of an affiliate's loss today, rather than having to wait until a later time when the affiliate has a gain. In other words, a consolidated tax filing also allows for the corporation to realize the advantage of the time value of money, thereby creating a tax shield.

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341 Dallas Exhibit 1, Schedule JP-4 at 3 of 8

342 Dallas Exhibit 1 at 52-54, and Schedule JP-4 at 3 of 8.

343 PUC Docket No. 22350, *Application of TXU Electric Company for Approval of Unbundled Cost of Service Rate Pursuant to PURA §39.201 and Public Utility Commission Substantive Rule §25.33,* Proposal for Decision Phases III & IV: T&D Revenue Requirement, Cost Allocation, TXU Business Separation, and Excess Mitigation of Stranded Costs at 108 - 114 (Nov. 27, 2000) and Order (Oct. 4, 2001).

In Public Utility Docket (PUC) Docket No. 14965, the PUC found that it was appropriate to require a consolidated tax savings adjustment known as a "tax shield." In an appeal of that docket, the Third Court of Appeals deemed the Commission's tax shield calculation methodology to be acceptable, but ultimately upheld the District Court's reversal for lack of record evidence supporting the Commission's calculation.[344] Therefore, because the Examiners found that TXU presented no evidence in this proceeding showing whether the consolidated tax filing would provide savings to the gas utility customers or the amount of savings that would be realized from a consolidated tax filing, TXU should be denied its request for the costs of tax filing preparation.

Although the Gas Utility Regulatory Act (GURA) does not address the treatment of a consolidated tax savings, an argument can be made that §104.055 requires that the beneficial savings recognized by a utility's consolidated tax filing should be passed to the ratepayer.

TUC §104.055(c) provides that "if an expense is allowed to be included in utility rates, or an investment is included in the utility rate base, the related income tax deduction or benefit shall be included in the computation of income tax expense to reduce the rates. If an expense is disallowed or not included in utility rates, or an investment is not included in the utility rate base, the related income tax deduction or benefit may not be included in the computation of income tax expense to reduce the rates. The income tax expense shall be computed using the statutory income tax rates."

TUC §104.055(e) provides that "section 104.055 is not intended to increase gas utility rates to the customer not caused by utility service. Utility rates may include only expenses caused by utility service." Therefore, the Examiners conclude that TXU should have presented evidence of the savings it will receive when it prepares a consolidated tax filing for the corporation.

54200000 Claims & Legal Admin Services

Expenses associated with the investigation and resolution of liability claims and lawsuits filed against the affiliates.

<u>*TXU's Position*</u>

TXU requested Commission approval of $1,176,913 for Distribution and $30,971 for Pipeline, for inclusion in the rates paid by TXU Gas' customers for Corporate Services-Administrative Claims and Legal Administrative Services associated with Project No. 54200000. TXU disagreed with ACC's position and argued that the costs assignments to the various TXU entities utilizing this service are based on time tracking. Therefore, the time tracking records reflect what actually occurred during the test year and represent what is most likely to occur on an ongoing basis.

TXU also rejected Dallas's proposed adjustment to total expense for Activity/Project 54200000 because, contrary to Dallas's assertions, the total costs for this Activity/Project have not been erratic over the past three years. Rather, the costs increased from year to year reflecting an increased need for these services. TXU argued the expenses are reasonable, necessary, and reflect an appropriate level of expense for this

344 *Application of Central Power and Light Company for Authority to Change Rates*, Docket No. 14965, Second Order on Rehearing (Oct. 16, 1997); *Central Power and Light Company v. Public Utility Commission*, 547 S.W.3d 547 (Tex. App.-Austin 2000, writ requested).

service.

ACC's Position

ACC noted that total expenses increased 65 percent between 2000 and 2002, climbing from $1.9 million to $3.1 million. Meanwhile, expenses allocated to Distribution almost tripled over the same period. ACC recommended that the adjusted test year be limited to the average amount of expenses over the three years, or $823,074. ACC stated that this project showed an extraordinary level of expense in 2002 that was not representative of ongoing expenses. ACC based its adjustment upon a comparison of the test year allocated expense with prior years' expenses for the same activity. ACC observed that the project may have represented an ongoing activity, but that the test year amount was anomalously high compared to past years. ACC adjusted the test year costs to reflect a more likely level of expense based on historic expenses. ACC recommended the following adjustment to derive a cost adjusted expense:

Distribution:	($353,840)
Pipeline:	-0-

Dallas's Position

Dallas reported that TXU Business Services allocates these costs to affiliates based on time tracking, but revised the allocation factor annually. Based on its review of TXU's historical pattern, Dallas concluded that TXU's request in this proceeding was excessive because the test year costs, $3,097,140, represented a twenty percent increase over the cost level claimed by TXU in GUD 9313 and is approximately thirty-eight percent higher than the base year in PUC Docket No. 22350, which was TXU Electric's unbundled cost of service (UCOS).

Dallas reasoned that it is possible for these costs to vary year to year; therefore, a single year snapshot of the level of cost incurred during any year may not be representative of an average level appropriate for ratemaking purposes. Dallas concluded that based on its review of the prior rate proceedings, TXU's test year request was excessive.

Thus, Dallas recommended to calculate the overall level of expense in Project No. 54200000 using normalization principles based on the average of the annual project cost levels reflected in this proceeding, GUD 9313, and the base year for PUC Docket No. 22350. Dallas recommended an average expense of $2,645,289 rather than $3,097,140 requested by TXU.

Dallas recommended an additional adjustment to the allocation to Distribution and Pipeline. Dallas performed the same normalization calculation regarding the total level of expenses and applied it to the allocable percentage to Distribution and Pipeline. This normalization reduced the allocable portion to Distribution by approximately 7.5 percentage points but increased the allocation to Pipeline by approximately 4/10 of a percentage point. Therefore, Dallas recommended a reduction in expense for this project of $372,544 for Distribution, but an increase in expense of $5,324 for Pipeline.[345]

Examiners' Recommendation

TXU provided no evidence to show why the costs had increased from year to year, but concluded nonetheless that the higher costs reflected an increased need for these services. The Examiners did not find

[345] Dallas Exhibit 1, Schedule JP-4 at 5 of 8.

probative TXU's arguments that the requested level of costs is reasonable. Because TXU failed to present credible evidence to support its position, the Examiners recommend disallowance, consistent with ACC's proposal. It is reasonable for the Commission to allow $30,971 for Pipeline. It is reasonable for the Commission to adjust TXU's request and allow Distribution expense of $823,073 ($1,176,913 - $353,840 =$823,073).

54300000 Corporate Security Services

Services associated with examining the effectiveness of safeguards for protecting system assets from loss and investigating losses and related violations of the utility's policy. TXU Business Services assigns corporate security costs to its affiliates according to time spent on providing the services.

TXU's Position

TXU requested Commission approval of $202,338 for Distribution and $49,351 for Pipeline, for inclusion in the rates paid by TXU Gas customers. TXU explained that because the Corporate Security Services organization does not have a time tracking system that allows it to contemporaneously assign the cost of its services during the test year, this organization historically used the prior years' timekeeping records to assign current year costs. TXU stated that during 2001, approximately 12.5 percent of Corporate Security Services' 2001 time was spent on behalf of Distribution. Management of the Corporate Security Services organization reviewed the level of service it provided to clients and adjusted its billing percentages based on professional judgment. Following such a review, the management of the Corporate Security Services organization utilized a rate of 8.2 percent in 2002. TXU argued that the Activity/Project 54300000 expenses reflected in TXU Gas - Distribution's cost of service are reasonable, necessary, and reflect a normalized level of expense for this service.

ACC's Position

ACC compared the test year 2002 allocation factor with prior years' allocations for the same activity. ACC observed that either an allocation factor changed appreciably during the test year, or the allocation factor to Distribution or Pipeline was incorrect. ACC assigned a revised allocation factor based on the prior years' allocations to yield a more equitable assignment of costs.

ACC noted that while total Corporate Security Services expense grew just 10 percent over the period, the share assigned to TXU Gas Distribution climbed from 3.0 percent in 2000 to 4.3 percent in 2001 to 8.2 percent in 2002. TXU argued that Corporate Security averaged 8 percent of its billable hours on behalf of TXU Gas Distribution over the three year period, but that this assertion was not supported by the affiliate billing data provided by TXU. ACC recommended that the allocated amount to TXU Gas Distribution be limited to 4.3 percent of the test year total, or $106,104. ACC recommended the following adjustment to derive an allocation adjusted expense:

Distribution: ($96,234)
Pipeline: -0-

Examiners' Recommendation

TXU's explanation of its billing method indicates arbitrary assignment of costs. TXU stated that management reviewed the level of service it provided to clients and adjusted its billing percentages based on professional judgment and therefore utilized a rate of 8.2 percent in 2002. TXU failed to provide evidence explaining why the increase in the cost of these services is reasonable. It is reasonable for the Commission to allow $49,351 for Pipeline. It is reasonable for the Commission to adjust TXU's request and allow Distribution expense of $106,104 ($202,338 - $96,234 = $106,104).

54600000 Compliance & Corporate Ethics

Services associated with affiliate rules compliance resulting solely from Senate Bill 7 (electric utility restructuring).

TXU's Position

TXU requested Commission approval of $58,075 for Distribution and $33,042 for Pipeline, for inclusion in the rates paid by TXU Gas customers. TXU argued that, although the Corporate Ethics & Compliance organization originated upon the implementation of Senate Bill 7, the gas utility should not be denied the opportunity to ensure and require its employees to conduct themselves in an ethical manner. TXU reported that the tasks performed as part of Activity/Project 54600000 included ongoing Code of Conduct training, certification of TXU personnel, responding to inquiries, and maintaining an online Corporate Policy Manual. TXU stated that these tasks ensure that all TXU employees, including those of Distribution and Pipeline, are educated in and compliant with various ethical and compliance issues including, but not limited to, diversity, sexual harassment, insider trading, etc. This training benefits customers, regulators, and investors by providing additional assurance that TXU Gas employees are trained in, and performing their duties in, an ethical manner and in compliance with the law and acceptable standards.

ACC's Position

ACC argued that these costs are related to electric restructuring issues and should be borne only by TXU's electric company affiliate. ACC argued that none of these costs assigned by TXU Business Services to TXU Gas should be passed to TXU Gas customers. ACC recommended the following adjustments to remove non-recoverable expenses:

Distribution: ($58,075)
Pipeline: ($33,042)

Examiners' Recommendation

The Examiners find that costs of Project 54600000 result from the electric restructuring requiring business separation and, therefore, should not be assigned to TXU Gas customers. TXU failed to provide evidence showing that these costs, or portions of these costs, are directly attributable to gas utility services, thereby allowing the Examiners or the Commission to consider what portion of this account, if any, relates to issues other than business separation and electric restructuring requirements. It is reasonable for the Commission to adjust TXU's request and allow no Distribution expense ($58,075 requested - $58,075 adjustment = $0). It is also reasonable for the Commission to adjust TXU's request and allow no Pipeline expense ($33,042 requested - $33,042 adjustment = $0).

60320000 Corporate Tax Accounting

Expenses associated with accounting for all federal, state income, and other taxes; furnishing accounting information that is required for tax filing compliance; and providing tax-related regulatory support for regulated Business Units.

TXU's Position

TXU requested Commission approval of $207,264 for Distribution and $49,328 for Pipeline, for inclusion in the rates paid by TXU Gas' customers. (*See* TXU's argument under Activity/Project 53900000, at page 82.

ACC's Position

ACC compared the test year 2002 allocation factor with prior years' allocations for the same activity. ACC observed that either an allocation factor changed appreciably during the test year, or the allocation factor to Distribution or Pipeline was incorrect. ACC assigned a revised allocation factor based on the prior years' allocations to yield a more equitable assignment of costs.

ACC noted that total expenses increased 22 percent from 2001 to 2002, but the allocation to Distribution almost doubled, from 8.7 percent to 16.0 percent. ACC recommended that the 2001 Distribution allocation of 8.67 percent be applied to the test year total of $1,296,533 for allocated Distribution expenses of $112,409. ACC recommended the following adjustment to derive an allocation-adjusted expense:

Distribution: ($94,854)
Pipeline: -0-

Dallas's Position

Dallas observed that the tax proposed by TXU is hypothetical and fails to account for the utility's income taxes on a consolidated basis. TXU did not provide to ratepayers any benefit that would result from the TXU Corp. filing of a consolidated tax return. Because the utility failed to provide the data needed for Commission consideration of inclusion of consolidated tax savings component, Dallas recommended that customers should not pay for any cost of preparing and investigating income taxes. TXU's hypothetical tax calculation used for ratemaking ignores the actual tax accounting and related analyses associated with the maintenance of detailed records for filing tax returns. Dallas recommended that the Tax Preparation Costs (Projects 53900000, 60320000) $1,014,760 Distribution and $713,839 Pipeline be disallowed because ratepayers receive none of the benefits received by TXU for its consolidated return.[346]

Examiners' Recommendation

Under Project 53900000, the Examiners provided a thorough analysis and recommendation which is reaffirmed for 60320000, Corporate Tax Accounting. The Examiners have reviewed the evidence for any information relating to TXU's consolidated tax benefits. Because TXU failed to present evidence regarding the savings it would enjoy as a result of its consolidated tax filing, the Examiners recommend that the Commission disallow all expenses under project 53900000, including accounting for all federal, state income, and other taxes; furnishing accounting information that is required for tax filing compliance; and providing tax-related regulatory support for regulated Business Units.

TXU failed to prove that $207,264 for Distribution and $49,328 for Pipeline are reasonable and necessary costs; therefore, it is reasonable for the Commission to disallow these amounts, in total.

60347000 FIM-Migration & Upgrade

Expenses for functional support for the migration of the financial information management (FIM) database to Oracle database in a Unix environment, along with grading the architecture and software.

TXU's Position

TXU requested Commission approval of $91,553 for Distribution and $49,185 for Pipeline, for inclusion in the rates paid by TXU Gas customers. TXU stated that this account consists of costs of functional support for the migration of the FIM database to Oracle. Due to changing information technology, costs

[346] Dallas Exhibit 1 at 52-54; JP-4 at 3 of 8.

incurred to modify or upgrade existing hardware and software applications are incurred on a regular basis.

Therefore, TXU argued, costs of this nature are recurring and should be included in TXU Gas' requested cost of service.

ACC's Position
ACC argued that this database migration project is a stand alone, non-recurring project. ACC argued that while this item may have provided a benefit to TXU Gas customers at the time the expense was incurred, it is not an ongoing project or activity expense. ACC argued that because the activity was completed and was not recurring, it would be inappropriate to continue to recover these expenses from ratepayers. Therefore, it is reasonable to remove these expenses from TXU Gas cost of service. ACC recommended the following adjustments to remove as non-recurring expenses:

Distribution: ($91,553)
Pipeline: ($49,185)

Examiners' Recommendation
TXU failed to provide probative evidence that expenses for functional support for the migration of the financial information management (FIM) database to Oracle database in a Unix environment, along with grading the architecture and software, are necessary expenses for the provision of gas utility service, and that the costs are reasonable. TXU's statements that the expenses were incurred are not probative of the reasonableness or necessity of the amounts. The Examiners find that the migration project from FIM to Oracle was not an ongoing activity. The Examiners recommend the Commission disallow $91,553 for Distribution and $49,185 for Pipeline as non-recurring expenses.

60400000 Property Accounting
Expenses associated with managing processes for capitalization of construction charges; asset cost recovery processes; asset reporting and retirement; tracking and accounting for inventory; lease tracking and reporting; shared asset billing; transportation accounting and job order process monitoring, and regulatory support.

TXU's Position
TXU requested Commission approval of $722,793 for Distribution and $659,367 for Pipeline, for inclusion in the rates paid by TXU Gas customers. TXU revealed that Activity/Project 60400000 is assigned to TXU entities based on time tracking. TXU Gas provided supporting documentation regarding the amount of time spent on behalf of each TXU entity for the services provided through Activity/Project 60400000. This information reflected the actual time spent on behalf of all TXU entities, including TXU Gas - Pipeline, during 2002, to support the assignment of these costs. The increase in the pro rata share assigned to TXU Gas - Pipeline is primarily the result of Property Accounting's increased focus on TXU Gas - Pipeline's property accounting issues and use of an improved, more precise time tracking system, beginning in 2002. In 2001, the amount of time spent on behalf of TXU Gas - Pipeline's property records was limited by TXU's involvement in TXU Electric restructuring efforts. TXU argued that the Activity/Project 60400000 expenses reflected in TXU Gas - Pipeline's cost of service proposed amounts were reasonable, necessary, and reflected an appropriate level of expense for this service.

TXU disagreed with Dallas's proposal. TXU capital expenditures relate to the acquisition of an asset, the benefit of which extends over one or more accounting periods beyond the current period. Property

Accounting services include managing processes for capitalization of construction charges; asset cost recovery processes; asset reporting and retirement; tracking and accounting for inventory; lease tracking and reporting; shared asset billing; transportation accounting; and job order process monitoring. These services are ongoing and operational in nature. They are not part of the cost to acquire a capital asset and should not be capitalized. TXU argued that Dallas's recommendation should be rejected. TXU argued that the data used by Dallas to normalize 2002 are four years old. Dallas provided no evidence that these data reflected current expense levels, only that the proposed average is lower than the 2002 levels. TXU argued that the Activity/Project 60400000 expenses reflected in TXU Gas - Pipeline's proposed cost of service amounts are reasonable, necessary, and reflect an appropriate level of expense for this service.

ACC's Position
ACC compared the test year 2002 allocation factor with prior years' allocations for the same activity. ACC observed that either an allocation factor changed appreciably during the test year, or the allocation factor to Distribution or Pipeline was incorrect. ACC assigned a revised allocation factor based on the prior years' allocations to yield a more equitable assignment of costs. ACC noted that total expenses were relatively stable between 2001 and 2002, but the allocation to Pipeline more than doubled, from 7.3 percent to 16.9 percent. ACC recommended that the 2001 Pipeline allocation of 7.30 percent be applied to the test year total of $3,889,770 for allocated Pipeline expenses of $283,953. ACC recommended the following adjustment to derive an allocation-adjusted expense:

Distribution:	-0-
Pipeline:	($375,413)

Dallas's Position
Dallas asserted that these costs are assigned on an annual basis, and updated quarterly based on an internal assessment of staff assignments, with labor being the primary cost driver. Dallas observed Exhibit SNR-2 reflected that a total cost of $722,793 was assigned to Distribution and $659,367 was assigned to Pipeline. All Distribution costs were expensed while a small portion of Pipeline costs were capitalized, so the expense level reflected in the revenue requirement for Pipeline is reduced to $653,737.

Dallas recommended an adjustment to properly reflect an appropriate allocable percentage of costs to Distribution and Pipeline. Dallas's adjustment reflected that the allocable percent of charges to Distribution and Pipeline are excessive when compared to other historical test years utilized for ratemaking purposes. Dallas reviewed the allocation percentage for Distribution and Pipeline in the current case, in GUD 9313, and in PUC Docket No. 22350 to find that a 4 percent adjustment to Distribution related expenses, and a 69 percent adjustment to the Pipeline related expenses are appropriate .[347] Dallas noted that TXU's requested allocated level of costs to Pipeline is more than 170 percent greater than the level of costs assigned to Pipeline in GUD 9313 or the TXU Electric Company's UCOS filing before the PUC.

Based on a review of the project description and a review of TXU's historic practice, Dallas recommended an additional adjustment because, in Dallas's opinion, a significant portion of the costs should have been capitalized. The project description for this account discussed the managing process for capitalization of construction charges, asset cost recovery processes, and asset reporting and retirement. While it was difficult to determine the level of costs that should be capitalized, Dallas concluded that the 100 percent

[347] Dallas Exhibit 1, Schedule JP-4 at 4 of 8.

expense for Distribution and the 99.15 percent expense ratio for Pipeline, as proposed, were excessive. To further verify TXU's position, Dallas considered TXU's practice in a previous proceeding.

Dallas looked at a case that "ultimately led to GUD 9313," but did not provide citation to or name of that case. Dallas stated that in that un-cited case, TXU provided information for test year ending September 30, 2001, regarding TXU Business Services costs assigned to various accounts. In that data response, Dallas reported, TXU assigned 61.86 percent of the Distribution related costs to Account 923, an expense account. It assigned the balance, or 38.14 percent of the cost to Account 107, which is construction work in progress (CWIP), a capital account. Dallas argued that it is not appropriate to ignore the historic practice of assigning a portion of these project costs to account 107. Dallas recommended that 61.86 percent of the costs for this project be expensed, with the remainder being capitalized to Account 107.

Dallas recommended reductions of $294,081 to the Distribution revenue requirement and $420,553 for Pipeline, with corresponding increases to plant in service for the capitalized amounts.[348]

Examiners' Recommendation
The Examiners find the evidence adequate to determine that these costs are reasonable and necessary for the provision of gas utility service and recommend the Commission approve $722,793 for Distribution and $659,367 for Pipeline for property accounting.

81021000 Human Resources Information System (HRIS)
Expenses related to the support and maintenance of the Employee Information System (EIS) and maintenance of employee records. EIS provides the data warehouse for Employee and retiree records, compensation/payroll information, employment status/history, education/training, thrift/En$ave enrollment and participant information, retirement/term vested/surviving spouse data. Reporting is supported through client request and a pre-programmed menu system available to system users. This area also maintains the corporate employee records, complies with state and federal record retention regulations and responds to all legal and court subpoena requests.

TXU's Position
TXU requested Commission approval of $430,081 for Distribution and $169,996 for Pipeline, for inclusion in the rates paid by TXU Gas customers. TXU argued that the increase in total expenses related to Activity/Project 81021000 in 2002 compared to 2001 is primarily the result of increased information technology and amortization expenses associated with new software applications required to maintain and manage employee information. TXU argued that these are reasonable and necessary expenses and should not be disallowed. TXU argued that ACC's disallowance would significantly understate Distribution and Pipeline's requested cost of service amounts.

ACC's Position
ACC argued that total expenses increased more than 70 percent between 2001 and 2002, climbing from $2.9 million to $4.9 million. Similarly, expenses allocated to Distribution increased 48 percent and Pipeline increased 56 percent over the same period. ACC recommended that the adjusted test year be limited to the 2001 amount of $291,367 for Distribution and $109,056 for Pipeline. ACC stated that this

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[348] Dallas Exhibit 1, Schedule JP-4 at 4 of 8.

project showed an extraordinary level of expense in 2002 that was not representative of ongoing expenses. ACC based its adjustment upon a comparison of the test year allocated expense with prior years' expenses for the same activity. ACC observed that the project may have represented an ongoing activity, but that the test year amount was anomalously high compared to past years. ACC adjusted the test year costs to reflect a more likely level of expense based on historic expenses. ACC recommended the following adjustments to derive cost-adjusted expenses:

Distribution: ($138,714)
Pipeline: ($60,939)

Examiners' Recommendation

The Examiners find TXU's evidence to be credible that the increased costs for this project from 2001 to 2002 were due to information technology and amortization expenses associated with new software applications that were required to maintain and manage employee information. Therefore, the Examiners recommend the Commission approve TXU's request of $430,081 for Distribution and $169,996 for Pipeline.

81024000 Benefits Administration

Expenses related to the development and ongoing administration of employee benefit programs including Employee Retirement Income Security Act (ERISA)/governmental compliance, employee/retiree/manager interface, actuarial studies, developing employee/retiree communication, thrift/En$ave plan accounting, retirement counseling, legal/benefit plan interpretation and vendor management. Benefit programs include retirement (TU/ENS/EBASCO), thrift, medical (POs and HMOs), dental, prescription drugs (PCS/Mail-Order), life insurance, long-term disability, workers' compensation, employee transportation programs, service awards, appliance purchase plan, and energy conservation program.

TXU's Position

TXU requested Commission approval of $563,288 for Distribution and $220,979 for Pipeline, for inclusion in the rates paid by TXU Gas customers. In discovery, TXU described the expense level for Activity/Project 81024000 in 2001 as "an aberration." TXU explained that during 2001, the expenses for Activity/Project 81024000 had been reduced by a one-time, nonrecurring demutualization credit. Prior to 2001, TXU Business Services' insurance carrier had demutualized, i.e., went from being an insurance corporation owned by its policy holders to a publicly traded corporation. At the time of demutualization, TXU Business Services was issued common stock in the new publicly traded insurance corporation in an amount equal to its ownership interest. TXU Business Services subsequently sold this common stock for a gain. Because TXU Business Services is a not-for-profit, zero-net-income company, TXU Business Services used this gain to reduce the expenses associated with this service in 2001. The expense reduction amounted to $1,354,677 in 2001. Because this was a one-time, nonrecurring event that occurred in 2001, the 2001 level of expense does not reflect a normalized level of expense for Activity/Project 810240000 and should not be used to adjust Distribution's and Pipeline's requested cost of service amounts. TXU argued, therefore, that ACC's proposed partial disallowance should be rejected.

ACC:

ACC noted that total expenses increased 64 percent between 2001 and 2002, climbing from $3.9 million to $6.5 million. Similarly, expenses allocated to Distribution increased 48 percent and Pipeline increased 53 percent over the same period. ACC recommended that the adjusted test year be limited to the 2001 amount of $381,806 for Distribution and $144,328 for Pipeline. ACC stated that this project showed an extraordinary level of expense in 2002 that was not representative of ongoing expenses. ACC based its adjustment upon a comparison of the test year allocated expense with prior years' expenses for the same activity. ACC observed that the project may have represented an ongoing activity, but that the test year amount was anomalously high compared to past years. ACC adjusted the test year costs to reflect a more likely level of expense based on historic expenses. ACC recommended the following adjustments to derive cost-adjusted expenses:

Distribution:	($181,482)
Pipeline:	($76,651)

Examiners' Recommendation

The Examiners find TXU's evidence to be credible that during 2001, expenses for Activity/Project 81024000 were reduced by $1,354,677 due to a one-time, nonrecurring event, i.e., the sale of common stock in a publicly-traded insurance corporation. Because this was a one-time, nonrecurring event in 2001, comparison with the test year amounts produces skewed results. The Examiners find that TXU's request of $563,288 for Distribution and $220,979 for Pipeline, is reasonable.

83010000 Procure Resources-Acquisition Services

Expenses to provide materials/services, when needed, at lowest evaluated cost, establish alliances with key suppliers/contractors, locate and develop qualified minority/women owned businesses.

TXU's Position

TXU recommended the Commission approve a total of $663,168 and $804,153 of Activity/Project 83010000 costs to be assigned to Distribution and Pipeline, respectively.[349] TXU considered Dallas's recommendation to be "piecemeal" ratemaking, to ignore test-year-based ratemaking principles, and to be unsupported by evidence. Dallas's data to "normalize" 2002 are four years old. Dallas provided no evidence that its data reflect current expense levels. Rather, Dallas's data are simply lower than the 2002 levels. The billing for Activity/Project 83010000 is based on an assessment of dedicated resources. TXU provided at TXU Exhibit 28, SNR-R-2, a calculation how the level of dedicated resources for 2002 was established for all TXU entities, including Distribution and Pipeline.

TXU argued that the level of services in Activity/Project 83010000, required by Distribution remained relatively steady over the four year period selected by Dallas and requires no adjustment. The Activity/Project 83010000 billings to Pipeline were not erratic. Rather, the billings demonstrate an increased need for this service over the past four years, i.e., the pro rata share of billings from Activity/Project 83010000 to Pipeline for the test years ended September 30, 1999, September 30, 2001, and December 31, 2002, have been 5.82 percent, 9.59 percent, and 11.44 percent, respectively. TXU argued that it provided support for the level of expense billed to both Distribution and Pipeline during 2002. The expenses proposed by TXU for inclusion in Distribution's and Pipeline's cost of service are reasonable, necessary, and reflect an appropriate level of expense for this service.

[349] TXU Exhibit 15, Schedule SNR-2.

Dallas's Position
Dallas compared TXU's proposed allocable percent of charges to Distribution and Pipeline to other historical test years previously utilized for ratemaking purposes and concluded the proposed charges were excessive.

Dallas noted that the assignment to Distribution was within three percent of the average of the test years analyzed, but that Pipeline was approximately twenty-eight percent higher than the average.[350] Dallas also noted that the test year allocable percentage for Pipeline is approximately ninety-seven percent greater than the allocated percentage to Pipeline reflected in TXU's electric affiliate UCOS filing, PUC Docket No. 22350. Dallas proposed an adjustment to normalize the expense level resulting in a $17,496 reduction to Distribution revenue requirements and a $175,305 reduction for Pipeline. [351]

Examiners' Recommendation
TXU's evidence consists of statements that these are the reasonable and necessary costs for expenses to provide materials/services, when needed, at lowest evaluated cost, establish alliances with key suppliers/contractors, and to locate and develop qualified minority/women owned businesses. TXU offers no probative evidence to show why or how these costs are reasonable or to explain why the requested cost for Pipeline is twenty-eight percent higher than the average of the same costs for the three test years Dallas used as a comparison. Merely stating that money was spent for this project is not adequate proof to establish reasonableness and necessity. Therefore, it is reasonable for the Commission to disallow Distribution costs of $663,168 and Pipeline costs of $804,153.

13WELLNS Wellness
Expenses related to developing and supporting a hazard-free environment.

TXU's Position
TXU requested Commission approval of $29,425 for Distribution and $20,226 for Pipeline, for inclusion in the rates paid by TXU Gas' customers. TXU argued that the amounts billed through Activity/Project 13WELLNS and Activity/Project 13SAFETY reflect costs of two separate and distinct services. TXU described Activity/Project 13WELLNS as costs to promote healthful lifestyle choices among TXU employees, including programs to provide education to employees regarding nutrition, exercise, tobacco cessation, etc. TXU argued that by encouraging employees to live a more healthful lifestyle, TXU is better able to hold healthcare costs to a minimum while maintaining, and even increasing, employee productivity.

TXU described Activity/Project 13SAFETY as the costs incurred to ensure a safer working environment, including ensuring legal and regulatory compliance (e.g., OSHA compliance), developing and administering safety policies and programs, and consulting related to workplace safety issues. TXU argued that both of these services are necessary and benefit TXU Gas customers by helping hold down healthcare costs and increasing employees' productive time spent on the job. TXU argued that because TXU Business Services is a not-for-profit, zero-net-income company, charging twice for the same expenses would have yielded a net income equal to this double charging, which did not happen. TXU argued that these costs are reasonable and necessary and should be included in TXU Gas' cost of service.

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[350] Dallas Exhibit 1, Schedule JP-4 at 7 of 8.
[351] Dallas Exhibit 1, Schedule JP-4 at 7 of 8.

ACC's Position
ACC argued that this project description is exactly the same as Project 13SAFETY and that the costs were redundant of the same activity; therefore, ACC concluded the costs should be removed from cost of service. ACC argued that none of these costs assigned by TXU Business Services to TXU Gas (Distribution or Pipeline) should be passed to TXU Gas customers. ACC recommended the following adjustments to remove non-recoverable expenses:

Distribution: ($29,425)
Pipeline: ($20,226)

Examiners' Recommendation
TXU's evidence consists of the statement that because TXU Business Services is not-for-profit, its expenses are reasonable and necessary. The Examiners do not find record evidence to show that the healthful lifestyle programs and education relating to nutrition, exercise, and tobacco cessation under Project 13WELLNS are reasonable and necessary for the provision of gas utility service. Therefore, having considered the evidence, the Examiners find that it is reasonable for the Commission to disallow, as a non-recoverable expense, $29,425 for Distribution and $20,226 for Pipeline as proposed in Project 13WELLNS.

428X0000 Information Technology Projects
Activities associated with implementation of new and/or upgrade of existing technological applications.

TXU's Position
TXU rejected ACC's proposed $777,276 reduction to Pipeline's cost of service that ACC based upon an average of 2000, 2001, and 2002 expenses. TXU averred that ACC's proposed averaging of IT client project expense was "piecemeal" ratemaking, was flawed because ACC proposed disallowance based on incorrect numbers and assumptions, and was not supported by evidence. TXU argued that ACC's proposed disallowance for Pipeline's IT client projects, amounting to $777,276, should be rejected.

TXU stated that ACC's approach is piecemeal ratemaking because ACC presented only cost decreases rather than also including recommendations for increased costs. TXU stated that for Pipeline, ACC's IT client project expense average is lower than for 2002 alone. Using ACC's presentation of IT client project expenses for these same years, Distribution's average IT client project expense would be $1,213,610, or $430,863 higher than the test year amount. However, in the case of Distribution, ACC proposed that the test year amount is appropriate.

TXU also argued that ACC's amounts for IT client projects do not represent the amounts that Distribution and Pipeline requested in cost of service. TXU asserted that during the test year Distribution and Pipeline were billed $782,747 and $2,466,601 for IT client projects, respectively. However, only $675,921 and $656,007 were expensed and proposed for inclusion in cost of service. TXU stated that, in other words, Distribution capitalized $106,826 of its $782,747 billed amount and Pipeline capitalized $1,810,594 of its $2,466,601 billed amount. TXU believed ACC's proposal was severely flawed because it would reduce Pipeline's cost of service by $121,269 more than TXU proposed ($777,276 - $656,007).

TXU challenged that ACC failed to distinguish between capital and operation and maintenance (O&M) client projects in each year presented. For the years 2000, 2001, and 2002, Distribution's expenses, excluding capitalized amounts, were $857,484, $885,122, and $675,921, respectively. For the years 2000, 2001, and 2002, Pipeline's expenses, excluding capitalized amounts, were $391,404, $672,986, and $656,007, respectively. Therefore, TXU concluded, IT client project expense amounts were lower in 2002 than in 2001 for both Distribution and Pipeline.

ACC's Position
ACC noted that approximately 52 IT projects were charged to Distribution or Pipeline during the test year. ACC stated that while many of the specific projects conducted during the test year closed, TXU argued that the constant change in available new technology and the continual need to enhance or upgrade existing technologies created need for ongoing IT support. ACC agreed that, rather than identifying and removing specific projects that have closed, it is sensible to look at the total group of IT projects. Exhibit KJN-6 compared the total dollar amount of IT projects for Distribution and Pipeline for the years 2000 through 2002. ACC noted that only one of the 52 projects allocated dollars to both Distribution and Pipeline. Therefore, it was appropriate to look at the project dollars allocated to the affiliates separately. ACC acknowledged TXU's argument that the costs for this project are relatively consistent from year to year, but ACC found that Pipeline IT project expenses roughly doubled from 2000 to 2001, and doubled again from 2001 to 2002. ACC argued that TXU provided no evidence that its unadjusted test year expenses reasonably represent future expenses. Because the specific projects change from year to year, as stated by TXU, it is reasonable to look at an average of these expenses over time. ACC recommended the level of IT expenses for Pipeline be adjusted to reflect the three year average of IT expenses, or $1,689,325.

Examiners' Recommendation
Having considered the evidence, the Examiners find that the costs for information technology projects associated with implementation of new or upgrade of existing technological applications are reasonable and necessary for the provision of gas utility service. The Examiners recommend the Commission include the amounts requested by TXU that were expensed and proposed for inclusion in cost of service, i.e., $675,921 for Distribution and $656,007 for Pipeline.

TXUWINS1 TXU Worldwide Integrated Support
TXUWINS1 was TXU's program to redesign the delivery of general and administrative services throughout TXU's global operations.

TXU's Position
TXU requested $210,162 for Pipeline and $300,680 for Distribution. The Examiners provide thorough analysis of the WINS issue in the WINS section of the Proposal for Decision (PFD). Consistent with the Examiners' recommendation to disallow WINS-related costs and to increase calculated WINS-related savings, the Examiners reaffirm their recommendation to disallow TXU's request for inclusion of WINS costs.

2. Service Level Agreement (SLA)

One of the affiliate transaction costs proposed by TXU is the Service Level Agreement (SLA) between TXU Gas and its affiliate, TXU Energy. The SLA is a fixed cost for five years. TXU Gas outsourced billing and customer care services to TXU Energy. Before the Commission can approve amounts relating to this SLA affiliate transaction, TUC §105.055 requires that TXU must show and the Commission must specifically find (1) that the expenses for billing and customer care services are reasonable and necessary for the provision of gas utility service; and (2) the charges by TXU Energy to TXU Gas under the SLA are no higher than the prices charged by TXU Energy to other affiliate or non-affiliate entities for the same item, class of items, or services.[352] The services were provided under an Interim Service Agreement beginning January 1, 2002, and the same services continued under the SLA effective October 17, 2002.[353]

Billing and customer care services were described by TXU to include:

- Customer Information Service (CIS) services - the ability to establish new accounts, assign accounts to rate plans, accept meter reads, calculate bills, forward billing files, update accounts with payments, and manage account exceptions;
- Bill Processing and Presentment Services - accepting billing data from CIS, reformatting data into print ready format (if not delivered in that format from the CIS), and bill printing and exceptions handling;
- Bill Payment Processing Services - the receipt of checks, electronic funds transfers, and charge card payments, the processing of those payments, the application of payments to accounts, and the handling of payment exceptions; and
- Customer Care Services - the use of the telephone, e-mail, or the Internet to establish new accounts, to answer customer questions on existing accounts (including payment plan options, payments, billing adjustments, and other customer inquiries), and to disconnect accounts.[354]

The SLA also provided that if actual uncollectible write-off performance is below a certain quarterly and annual target, TXU Energy is credited for the difference. If actual performance is above targets, TXU Gas is credited with 50 percent of the write-off difference.[355] Although the test year for most aspects of GUD 9400 was calendar year 2002, TXU's test year for SLA data was calendar year 2000. TXU records SLA expenses to NARUC Account 903, Customer Records and Collections Expenses.[356] During the test year, TXU Gas was credited with $963,459 for write-off performance, which was included in Account 904, Uncollectible Accounts.[357] TXU Energy's lease payment to TXU Gas in the amount of $749,835 was recorded in Account 493, Rent from Gas Property.[358]

In accordance with the provisions of TUC §104.055, to be approved as either a capital cost or an expense, transactions between affiliates require specific findings by the Commission that the payments between affiliates are reasonable and necessary. The Commission must also find, specifically, that the price to the gas utility is not higher than the prices charged by the supplying affiliate to its other affiliates or divisions or to a non-affiliated person for the same item or class of items. Under the SLA, TXU Gas pays to TXU Energy monthly installments of $2,444,517.[359] TXU Gas proposed that the Commission approve recovery through rates of a $29,334,204 per year expense for customer care and billing services under the SLA ($2,444,517/month x12 months = $29,334,204). This is the fixed annual price for the five-year term of

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352 TUC §104.055; TXU Exhibit 16 at 15; TXU Exhibit 29 at 18.
353 TXU Exhibit 16 at 19-42.
354 TXU Exhibit 16 at 4-5.
355 TXU Exhibit 16, attachment BMG-3 at 3 of 17; ACC Exhibit 4 at 18.
356 TXU Exhibit 17 at 19.
357 ACC Exhibit 4 at 18.
358 ACC Exhibit 4 at 18.
359 TXU Exhibit 16 at 38; TXU Exhibit 16, attachment BMG-3 at 3 of 17; TXU Exhibit 17 at 19.

the SLA.[360] An additional transaction occurs under the provisions of the SLA. TXU Energy leases from TXU Gas its customer information system (CIS) for $62,486 per month ($62,486/month x 12 months = approximately $749,835).[361]

<u>TXU's Position</u>

TXU Gas paid $29,334,204 to TXU Energy in the test year. TXU requested inclusion in cost of service expenses of $29,334,204 for SLA expenses recorded to NARUC Account 903 and sought approval of a reduction of ($963,459) recorded to NARUC Account 904 for the credit related to uncollectible write-offs. TXU stated that its test year 2000 for this SLA issue was the year with the lowest uncollectible write-off percentage over the last eight years.[362]

TXU argued that neither Dallas nor ACC presented credible evidence to establish that the price paid by TXU Gas under the SLA was unreasonable. In addition, none of the Intervenors challenged either the necessity of the SLA costs or the fact that the price paid by TXU Gas under the SLA was no higher than the price charged by TXU Energy to other entities for the same type of services. TXU argued that the evidence showed that the rates for the SLA are reasonable and necessary for the provision of gas utility service, and that the charges by TXU Energy to TXU Gas were no higher than the prices charged by TXU Energy to other entities for the same services.

TXU argued that the evidence established that the amount TXU Gas paid for the SLA services during the test year was reasonable and was financially an "excellent" deal for TXU Gas.[363] TXU considered three options with respect to billing and customer care services. TXU Gas could have: (1) contracted for billing and customer care services from an outsource company; (2) contracted with TXU Energy to provide the services; or (3) developed and built its own customer service facilities.[364]

TXU stated that the TXU Energy option provided the lowest operating cost, capital investment, and implementation risk, while providing the highest probability of service performance.[365] TXU compared the $29,334,204 it paid for the SLA services during the test year to the $33,175,101 that was the minimum expense actually incurred by TXU Energy during the test year to provide the SLA services, and concluded that the costs paid by TXU Gas under the SLA were reasonable.[366] TXU summarized the cost savings as follows:

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[360] TXU Exhibit 16 at 28 and 38; TXU Exhibit 29 at 2 -16.
[361] TXU Exhibit 16, attachment BMG-3 at 3 of 17; ACC Exhibit 4 at 18.
[362] TXU Exhibit 16 at 38; TXU Exhibit 16 at 29 at 2 and 11; TXU Exhibit 17 at 19.
[363] Tr. Vol. 4 at 101.
[364] TXU Exhibit 16 at 5.
[365] TXU Exhibit 16 at 5-6.
[366] TXU Exhibit 28 at 55; TXU Exhibit 29 at 7-20.

TXU's Summary of Cost Savings[367]

Year	# Accounts	TXU Energy Option	Outsource Option	TXU Gas Option
1	1,498,877	$29,334,204	$35,795,331	$32,927,936
2	1,530,353	$29,334,204	$37,277,392	$34,027,112
3	1,562,491	$29,334,204	$38,806,028	$35,169,160
4	1,595,303	$29,334,204	$40,401,636	$36,355,897
5	1,628,805	$29,334,204	$42,066,804	$37,589,215
Total		$146,671,020	$194,347,191	$176,069,320

TXU addressed Dallas's arguments relating to the SLA. Dallas challenged that TXU did not prove the reasonableness of the SLA. Dallas recommended that TXU should have used 2001 costs as the basis for the SLA expenses. TXU responded that:

- TXU Gas did not base its SLA costs on the higher cost months experienced in 2001, but rather on the lower cost months experienced in 2000;
- Dallas presented no evidence that the test year 2000 costs used to establish the price under the SLA were anything but normal and representative;
- Dallas's method was piecemeal ratemaking because the data was a comparison of the four highest cost months in 2001 with the four lower costs months in 2000;
- Dallas's approach to normalize 2001 SLA costs was inconsistent with the methodologies used by Dallas to normalize other costs.
- consideration of Dallas's proposal would require evaluation of data that had not been available to TXU Gas at the time the SLA decision was made during June or July of 2001; and the actual cost for billing and customer care services during 2001 was $30,505,408, which was almost $1.2 million higher than the costs experienced during 2000.[368]

Dallas challenged that costs incurred during calendar year 2000 were assumed to be the representative level of SLA expenses. TXU responded that:

- TXU Gas reviewed the line-by-line 2000 costs and allocation methods, used external benchmarks to verify 2000 costs, and made this information available to Dallas in a response to an RFI;
- the allocation methods used in 2000 were favorable to TXU Gas by providing lower costs than other available allocation methods. For example, TXU Gas received 20 percent of the cost allocation for CIS, where an allocation based on accounts would have required an allocation of costs to TXU Gas of over 30 percent;

[367] TXU Exhibit 16 at 13.

[368] TXU Exhibit 29 at 3-7; Tr. Vol. 4 at 66-67, 94-95, and 112-13.

- the allocation of costs within the call center was calculated based on the number of calls, although an allocation based on productive minutes would have allocated more costs to TXU Gas;
- comparisons to external vendor costs were conducted and showed that the unit costs, as calculated for 2000, were at or below industry benchmark costs; and
- that analysis of the call center using standard Erlang applications and efficiency analyses found results that if TXU Energy had provided customer care services to TXU Gas for a price based on year 2000 costs, TXU Gas would have received these services at a significantly lower cost than if TXU Gas had provided the services to itself on a stand-alone basis.[369]

TXU concluded that it made a careful review of the data that were available at the time it selected 2000 as the pricing basis for the SLA. TXU argued that the evidence established that no savings from the WINS effort would be realized with respect to TXU Energy's call center operations.[370] TXU also argued that Dallas's statements were without support and should be rejected.

TXU stated that the SLA expenses paid by TXU Gas during the test year, pursuant to the provisions of the SLA, were at or below the actual cost for the services for each year during the period between 1999 and 2002. TXU provided the following chart to establish that Dallas's recommendation results in SLA expenses that are more than $8 million below the actual costs to provide the services in 2002.

TXU's Comparison of SLA and Negotiated SLA Expense[371]

YEAR	SLA Associated Expenses	Difference from Negotiated SLA Expense
1999	$29,426,339 (note *a*)	$92,135
2000	$29,334,206 (note *a*)	$2 (note *b*)
2001	$30,085,985 (note *a*)	$751,781
2002	$33,175,101 (note *c*)	$3,480,895
Average	$30,505,408	$1,171,204
Dallas's Recommendation	$25,152,229	($4,181,977)

Note *a* – Gillespie Rebuttal: TXU Exhibit 29, attachment BMG-R-1.
Note *b* – The $2 difference results from rounding the applicable numbers.
Note *c* – Ragland Rebuttal: TXU Exhibit 28 at 55.

TXU addressed ACC's arguments relating to the SLA. ACC challenged that it is not possible to determine the reasonableness of the SLA expenses based on the record evidence. TXU responded that plethora of record evidence establishing the SLA expenses were reasonable and that:

- the SLA provided the lowest operating cost, capital investment, and implementation risk for TXU Gas, while providing the highest probability of service performance;

[369] TXU Gas Exhibit 29 at 9-10.
[370] TXU Gas Exhibit 29 at 9-10.
[371] TXU Exhibit 29 at 7; TXU Initial Brief at 108 (Mar. 8, 2004).

- contracting with TXU Energy provided the lowest cost option for TXU Gas by $4 to $12.5 million per year over the outsourcing option, and by $3.5 to $8 million per year over the TXU Gas owned-and-operated system option;
- under the SLA, TXU Energy leased TXU Gas' customer information system (CIS) from TXU Gas at an amount equal to the amortization for the system over the life of the system;
- under the SLA, TXU Energy absorbed 50 percent of uncollectible write-offs exceeding the 2000 performance level of 0.37 percent, which was the lowest uncollectible write-off percentage in recent history;
- the price under the SLA is fixed for the term of the agreement so TXU Gas is not subject to cost increases due to inflation, an increase in account volume, or other factors;
- the SLA provides the lowest risk alternative to TXU Gas with respect to billing accuracy and timeliness;
- TXU Gas paid only $29,334,204 under the SLA during the test year at a time when TXU Energy incurred expenses of $33,175,101 to provide these services;
- the SLA was drafted so that enhancements to the CIS system are part of the fixed price of the SLA; and
- the adjustments that were made to the 2000 book costs related to the SLA were those costs that were reasonable and necessary for the services to be provided to TXU Gas.[372]

TXU argued that ACC's recommendation of a $4,971,200 reduction to SLA expenses was based on ACC's conclusion that the number of customer care advocates (CCAs) available to answer calls declined by 239 from 2000 to 2003. TXU stated that ACC used Waco and Irving CCAs for calculating 2002 CCAs at 417, but used Waco only for its 2003 headcount of 178. TXU argued that this misrepresents the year-over-year comparison of CCAs. TXU also testified that TXU Energy operates its call centers as one virtual center, keeping the service levels of TXU Gas and TXU Energy consistent. Thus, the more appropriate comparison would be the total headcount in Waco, Irving, and outsource vendor because the use of the outside vendor for TXU Energy calls allows internal CCAs to answer more of the TXU Gas calls. TXU suggested that inclusion of the FTEs for all three groups would be a more accurate comparison.[373] TXU reported that the total number of all FTEs supporting TXU Gas and TXU Energy actually increased by 4 percent from the beginning of the test year through the end of November 2003.[374] TXU summarized its position that the SLA expenses incurred during the test year were reasonable; the SLA costs were based on costs incurred during the lowest cost-year of the last four years.

TXU argued that the price paid by TXU Gas under the SLA was not higher than the price charged by TXU Energy to other entities for the same type of services. TXU stated that TXU Energy does not provide the same billing and customer care services as those provided under the SLA to any other affiliate or third party. Therefore, TXU rationalized, the price paid by TXU Gas under the SLA was not higher than the price charged by TXU Energy to any of TXU Energy's other affiliates or divisions or to a non-affiliated person for the same item or class of items. TXU stated that no intervening party contradicted this evidence.[375]

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[372] TXU Exhibit 16 at 5-14; TXU Exhibit 29 at 8; Tr. Vol. 9 at 133; Tr. Vol. 4 at 67-68; TXU Initial Brief at 109 (Mar 8, 2004).

[373] TXU Initial Brief at 110 (Mar. 8, 2004); TXU Exhibit 29 at 17; TXU Exhibit 29, attachment BMG-R-5.

[374] TXU Exhibit 29, attachment BMG-R.

[375] TXU Exhibit 16 at 15; Tr. Vol. 4 at 85-86; TXU Initial Brief at 110-111 (Mar. 8, 2004).

TXU summarized that the evidence established that the price paid by TXU Gas to TXU Energy under the SLA was reasonable, that the evidence proves that TXU Energy's provision of billing and customer care services to TXU Gas under the SLA are necessary to the continued provision of utility service to TXU Gas' customers, and that the price paid by TXU Gas under the SLA was not higher than the price charged by TXU Energy to any of TXU Energy's other affiliates or divisions or to a non-affiliated party for the same item or class of items. TXU argued that it met its burden of proof regarding the SLA costs. TXU requested inclusion in cost of service expenses of $29,334,204 for SLA expenses recorded to NARUC Account 903 and sought approval of a reduction of ($963,459) recorded to NARUC Account 904 for the credit related to uncollectible write-offs.

ACC's Position

ACC recommended a $4,971,200 reduction to TXU's cost of service because the payments made by TXU Gas to TXU Energy under the SLA were not reasonable and necessary. In addition, ACC recommended that TXU Gas file with the Commission on a quarterly basis the actual performance of TXU Energy for each measure listed in the SLA, Exhibit A entitled Customer Service Metrics, upon which a future evaluation or adjustment of the SLA can be based, if TXU Energy consistently fails to meet the contractually obligated performance standards.

ACC argued that TXU provided no support that its decision to outsource its customer care and billing services to TXU Energy was the lowest cost option. ACC noted that in rebuttal TXU was unable to provide data to support its conclusions regarding the low cost alternative; instead, TXU restated its direct case.[376] ACC challenged the list that TXU provided to support its position that the SLA expenses were reasonable. ACC noted that TXU's citations were to the testimony of Mr. Gillespie, a consultant hired by TXU to advise the utility on the SLA. ACC stated that Mr. Gillespie is not a regulatory expert, has not consulted on customer care issues for any other gas or electric utility in Texas, and has negotiated only one other contract between a regulated entity and an affiliate. ACC represented that TXU's opinions about the reasonableness of the SLA were unsupported and that TXU provided no evidence that its decision to outsource its customer care and billing services to TXU Energy was the lowest cost option.

In ACC's opinion, both staffing levels and the quality of service at the call centers dramatically declined since the SLA was executed. For both measures, the SLA targets were not met.[377] ACC reported that since TXU Energy assumed responsibility for customer calls under the SLA in 2002, the average time to answer general gas customer calls increased more than 50 percent and the abandoned call rate doubled.[378] (The abandon rate is the number of calls in which the customer disconnects before the call is answered, minus two percent of total calls.[379]) Therefore, ACC determined that the cost TXU Gas was paying to TXU Energy for the poor service could not be justified as reasonable and necessary. ACC's recommendation to reduce costs to TXU Gas customers was based on information that had been provided by TXU regarding call center staffing levels. ACC recommended a reduction of $4,971,200 to TXU's cost of service to account for the low level of service being provided under the SLA contract. ACC stated that because TXU did not provide sufficient information about salaries and headcounts, ACC based its recommendation on

[376] ACC Reply Brief at 70-71 (Mar. 17, 2004); TXU Exhibit 29 at 18; Tr. Vol. 9 at 136-137, 157-158.
[377] ACC Exhibit 4 at 23a-24.
[378] ACC Exhibit 4 at 24.
[379] TXU Exhibit 16, attachment BWG-3 at 12 of 17.

an estimate of the reduction of call center employees at the Waco center and salary and benefits assumption of $10 per hour.[380] ACC argued that its recommendation is reasonable, given the limited information TXU provided.[381]

ACC challenged that TXU did not support its position that the price paid by TXU Gas under the SLA was not higher than the price charged by TXU Energy to any other person for the same service. ACC questioned whether the SLA was an arm's length agreement.[382] ACC argued that TXU witness Gillespie stated that the SLA was an arm's length negotiated agreement, despite it being between affiliated companies; yet, the witness did not know whether the attorneys representing TXU Gas and TXU Energy were from the same firm. ACC stated that TXU's representation that separate teams participated in negotiations is irrelevant. ACC pointed to TUC §104.003(e) to argue that Texas statutes recognize that negotiations between affiliated companies are not "arms length" and to conclude therefore that without underlying support, TXU failed to show that entering into the SLA was in the best interest of gas customers.[383]

ACC postured that staffing levels at TXU's customer call centers did not support the level of payments in the SLA. ACC demonstrated that by 2003, customer call center staffing was significantly reduced since operation under the SLA began. At the same time, the expense paid under the SLA remained the same as staffing levels in 2000; therefore, ACC proposed to reduce costs to TXU Gas customers based on call center staffing levels. ACC questioned the validity of TXU's revised call center headcounts because TXU did not supplement its responses to intervening parties' RFIs to account for the additional 198 full time employees (FTE). These additional employees did not answer TXU Gas customers' calls.[384]

ACC went on to state that on January 14, 2004, TXU filed witness Gillespie's rebuttal testimony, including headcount numbers not previously provided to ACC in response to RFIs; but not including supporting workpapers. On January 20, 2004, TXU provided a spreadsheet that broke down the headcount numbers between internal and external FTEs, but provided no source for the data. The data differed from the data provided in discovery and relied on by ACC. In an attempt to get the source data used by Mr. Gillespie, ACC initiated a conference call with TXU on January 23, 2004. Witness Gillespie was included on the conference call. ACC reported that it still was unable to get the source of the information. As a result of the conference call, TXU provided on January 24, 2004, supplemental responses to several relevant RFIs. However, ACC considered the supplemental responses to be witness Gillespie's reinterpretation of the RFIs submitted by ACC to obtain call center headcount levels. ACC reported that, again, it received no source data from TXU. ACC stated that TXU was not responsive to Dallas's RFIs, either. ACC argued that without access to the source data relied upon by TXU witness Gillespie, his testimony is unsupported opinion and therefore should not form the basis of any findings in this case.[385] ACC noted that TXU

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[380] ACC Exhibit 4 at 23a.

[381] ACC Exhibit 4 at 20; ACC Initial Brief at 131 (Mar. 8, 2004); ACC Reply Brief at 71 (Mar. 17, 2004).

[382] ACC Exhibit 4 at 21.

[383] TXU Initial Brief at 110 (Mar. 8, 2003); TXU Exhibit 29 at 18; Tr. Vol. 4 at 93; ACC Reply Brief at 72 (Mar. 17, 2004).

[384] ACC Exhibit 4 at 21-22; TXU Exhibit 16 at 9; TXU Exhibit 29 at 17; TXU Exhibit 29, attachment BMG-R-5; TXU Initial Brief at 110 (Mar. 8, 2004); ACC Reply Brief at 72.

[385] TXU Exhibit 29 at 17; ACC Exhibits 67 - 70 are RFI responses relevant to the SLA, CCA issue; ACC Reply Brief at 73; Tr. Vol. 9 at 138-146, 166-175; 192-195.

witness Gillespie conceded that he never provided the source data[386] and that he never provided external FTE numbers to ACC.[387]

ACC recommended the Commission disallow costs for the SLA due to the CCA downsizing. ACC corrected TXU's understanding of how it derived its recommendation. TXU had understood that ACC used a combination of Waco and Irving call center headcounts for the 2002 beginning number, but used Waco alone for the 2003 ending number. ACC reported that it used the data provided by TXU, i.e., the data that reflected there were no gas-trained staff at the Irving facility by August 2003.[388] ACC argued that its recommended adjustment is the only reliable evidence in the record regarding gas customer service representatives, showing that staffing and customer support declined.[389] ACC reported that the number of CCAs at the Waco facility declined from 258 in January of 2002 to 178 in August of 2003.[390]

ACC questioned TXU witness Gillespie's credibility, due to his actions during discovery, his RFI responses, his demeanor on the stand, and his testimony. ACC suggested that it took extraordinary efforts, even after rebuttal testimony had been filed, to attempt to get source data, because TXU and Mr. Gillespie withheld information during discovery. ACC reiterated that TXU based its call center staffing counts on data that were not provided to ACC in response to RFIs. In response to ACC's claim that he did not disclose the requested information, Mr. Gillespie explained that he believed that ACC 1-99 asked specifically about call centers managed by TXU Energy, but that outsource vendors are not managed by TXU Energy.[391]

ACC made an additional recommendation that TXU be required to file quarterly performance reports of the actual performance under the SLA's performance measures. ACC argued that these results could be the basis for an adjustment to future SLA fees if performance consistently fails to meet agreed standards.

Dallas's Position

Dallas stated that TXU's request for $29 million in Distribution revenue requirements associated with the Service Level Agreement is not reasonable. Dallas argued that TXU witness Gillespie, an outside consultant who was hired to provide testimony relating to the reasonableness of the SLA, failed to show the reasonableness of the amounts requested.[392] Dallas argued that TXU's statements that SLA is at a fixed level for five years and that the SLA based upon year 2000 costs were not sufficient evidence to show the requested cost for the SLA is reasonable. Dallas recommended that the cost of the SLA be reduced by $4,181,977 because (1) the cost is excessive when compared to 2001 costs properly adjusted; (2) the actual costs for 2000 were not shown to be representative; and (3) the cost level does not reflect WINS savings.[393]

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[386] Tr. Vol. 9 at 141.

[387] Tr. Vol. 9 at 149-150.

[388] ACC Exhibit 4, Appendix E, TXU Gas Number of Customer Care Advocates (CCAs) at the Irving Facility.

[389] ACC Exhibit 4 at 22.

[390] ACC Exhibit 4 at 22; ACC Exhibit 67, Jan. 23, 2004 Supplemental Response by TXU to ACC's RFI 1-099, TXU Gas Number of Customer Care Advocates (CCA's) at the Waco Facility.

[391] Tr. Vol. 9 at 151.

[392] Dallas Initial Brief at 41.

[393] Dallas Exhibit 1 at 31-32.

Dallas noted that both Dallas and ACC had presented requests for information (RFI) to TXU asking for outsource vendor information. Like ACC, Dallas questioned witness Gillespie's candor, noting that the witness had not provided the information in a prompt manner because, "[o]utsource vendors are not managed by TXU Energy."[394]

Prior to the negotiation of the SLA, TXU Gas received billing services from TXU Business Services and customer care services from TXU Electric. Laws governing electric utility restructuring in Texas prohibited an electric transmission and generation company such as TXU Electric from providing billing and customer care services to an affiliated retail electric provider (REP) such as TXU Energy. Thereafter, the billing and customer care facilities became TXU Energy's. Because the electric restructuring law prevented TXU Electric from providing billing and customer care services to TXU Gas, TXU Gas sought other options. ACC reported that the reasonableness of the options could not be determined because the support provided for the decision could not be verified.[395]

Dallas considered that TXU Energy, the unregulated affiliate, intended to make a profit on the SLA. The agreement was executed at the time TXU was in transition to a restructured electric retail market; therefore, the SLA was made to protect TXU Energy by providing a revenue guaranty, against which it can cut costs. It was Dallas's position that TXU entered into the SLA to put its unregulated companies in a better position, and then engaged counsel and a consultant to give legitimacy to the process.[396] Prior to the SLA, TXU Electric had call centers and personnel in place to perform these same services. TXU Energy had an allocation agreement between TXU Electric and TXU Gas.[397] Dallas contemplated that the SLA and the process of establishing the SLA were conceived and used to manipulate the regulatory setting. Dallas argued that when the process began, Mr. Gillespie was engaged and his firm was paid approximately $120,000[398] in order to attempt to justify the expense in a regulatory setting.[399] The agreement was presumably negotiated at arms length with TXU Gas and TXU Energy representatives, including TXU Gas Company's regulatory counsel.[400]

Dallas questioned how TXU Energy could have entered into a fixed charge SLA with TXU Gas and still make a profit. Dallas decided that the answer was in the information that TXU withheld from the intervening parties -- that TXU Energy outsourced the electric side of its business. To support its position, Dallas referenced Tr. Vol. 9 at 138-139, 175, and 180. Dallas proposed that TXU did not consider and did not provide information whether TXU Gas could have also outsourced for the services provided under the SLA. Dallas argued that, regardless of the arrangement with TXU Energy under the SLA, TXU failed to present evidence that the cost level of the SLA was reasonable.[401]

Dallas argued that the SLA amount was based on the costs to perform activities during calendar year 2000, adjusted for claimed known and measurable changes. Dallas argued that calendar year 2000 costs were

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394 Tr. Vol. 9 at 151.
395 TXU Exhibit 16 at 4-6; ACC Exhibit 4 at 19.
396 Dallas Initial Brief at 42-43 (Mar. 8, 2004).
397 Tr. Vol. 4 at 96. (Dallas cited to Tr. Vol. 9 at 96.)
398 Tr. Vol. 4 at 87.
399 Tr. Vol. 4 at 105 -109.
400 Tr. Vol. 4 at 72-73 and 93-94.
401 Dallas Initial Brief at 40-42.

used by TXU because TXU thought calendar year 2001 costs were not representative; the costs in the first months of 2000 were atypical. TXU decided in early 2001 to use the higher costs to provide the level of the agreement. TXU's attempt to normalize the expense level resulted in a significant overstatement of costs, given that appropriately normalized costs during 2001, as calculated by Dallas, demonstrated a significant reduction in the cost of providing these same services.[402] Dallas also argued that the SLA costs should reflect reductions due to WINS savings. Proper normalization of the costs for these services, without recognition of additional WINS efforts, reduces Distribution expenses by approximately $4.2 million.[403]

Dallas recalled TXU's criticism of its proposed reduction. TXU had argued that Dallas had used information that had been available to TXU at the time the SLA was negotiated, that use now of the information was impermissible, that the costs of the SLA were lower than costs in prior years, and that TXU witness Gillespie represented that there were no WINS savings. Dallas countered TXU's position, stating that this is not an instance of using improper or unknown information.

Dallas challenged TXU's reliance on *Gulf States Util. v. PUC*, 841 S.W.2d 459 (Tex. App.–Austin 1992, writ denied) because the case does not stand for the proposition that the Commission cannot use the information available. Dallas argued that the Court decided that after-the-fact analysis is permissible, if not subject to more scrutiny.[404] Dallas argued that *Gulf States* indicated prudent decision making may be demonstrated in two ways. To recover costs in rates, a utility may show either that its decision making process was prudent, or that the same decision is in the select range of options that would have resulted had prudent decision making been employed. Dallas argued that under the first method, a utility presents contemporaneous documentation of its decision-making process, thereby enabling the Commission to review the actual investigations and analyses leading to the utility's decision. When there is no evidence of contemporaneous investigation and analysis, a utility may employ the second method, analyzing the prudence of the decision after-the- fact. An attempt to demonstrate prudent decision-making by retrospective analyses is inherently defensive and hence more suspect. Second, the Court reiterated that the burden of proof on such issues rests upon the utility.[405] Dallas argued that in this proceeding, TXU's claim that it could not have known of the information is not true because the interim agreement was signed in December of 2001[406] (at which time the costs for 2001 were known); the final agreement was signed October 17, 2002.[407]

Dallas demonstrated that a reasonable level of expense –excluding the extreme weather situations in early 2001– would be lower than the SLA level. TXU's suggestion that evaluation of these levels should not have occurred was incorrect. TXU Gas Distribution and TXU Energy had contemplated that the level of expense in the agreement would be adjusted, if the contract level was disallowed by the Commission. TXU Exhibit 16, attachment BMG-3 at 14 of 17, paragraph 6 provided options to TXU Gas Distribution

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402 Dallas Initial Brief at 42.
403 Dallas Initial Brief at 42; Dallas Exhibit 1 at 30-36.
404 *See* 841 S.W. 2d 459 at 475.
405 Dallas reply Brief at 27-28 (Mar. 17, 2004) quoting from *Gulf States Util. v. PUC*, 841 S.W.2d 459 (Tex. App.–Austin 1992, writ denied).
406 Tr. Vol. 4 at 88.
407 TXU Exhibit 16, attachment BMG-3 at 1.

and TXU Energy.[408] Dallas also took note that TXU Gas Distribution, rather than TXU Gas, is the entity that entered into the SLA with TXU Energy. [409]

TXU had argued that the costs of the SLA were lower than in prior years. Dallas represented that the real inquiry in this proceeding should consider the reasonable level of expense on a going-forward basis. Dallas addressed this issue by looking at factors relating to the costs of this service; however, TXU ignored those factors.[410]

Dallas addressed TXU's position that WINS savings belonged to shareholders and that contracting for this service with the unregulated TXU Energy, TXU Gas customers would not share in WINS savings benefits from the customer care service. Dallas noted that in rebuttal, TXU witness Gillespie testified that (1) TXU selected 2000 as the base year; (2) that TXU Gas understood that there may be savings through technology; and (3) that the WINS program focused on reducing general and administrative expenses, including FTE's at the call centers, through technology and outsourcing which would affect only TXU Energy**.**[411] Dallas responded that Mr. Gillespie's statements were inconsistent with TXU's contention that the 2001 cost level data had not been available for consideration and showed (1) that the SLA in this proceeding, signed after the WINS program was under way in 2002, did not contemplate that TXU Gas customers would receive any benefit from savings attributable to technology or outsourcing; (2) TXU's position that those savings were reserved to TXU Energy (the unregulated business); and (3) that TXU witness Gillespie did not fully understand that the SLA was with TXU Gas Distribution, not with TXU Gas.[412]

Dallas concluded that the SLA was an example of TXU's attempt to maximize the profits of the non-regulated side of TXU's business at the expense of the regulated side, i.e., TXU Gas Distribution. For that reason, Dallas urged that the SLA should be given greater scrutiny. Dallas argued that TXU failed to meet the burden of proof; therefore, the level of expense for the SLA should be fixed at $25,152,229 (an approximate $4,181,977 reduction). Dallas recommended the Commission adopt its recommended adjustment because TXU did not provide evidence that costs requested for the agreement are reasonable.

ATM's Position

ATM reported that it supported Dallas's recommendation to reduce Distribution expenses related to the SLA by $4,181,977 and supported ACC's proposed Distribution reduction of $4,971,200.[413]

Examiners' Recommendation

The Examiners considered the evidence relating to TXU's request for approval of the SLA expense as a cost of service. The evidence does not show that the requested expense of $29,334,204 for billing and customer care services is reasonable and necessary for the provision of gas utility service.[414] Therefore, rather than approving SLA expense levels as proposed by TXU, the Examiners recommend the Commission approve a $4,971,200 annual reduction, which is supported by the evidence. The Examiners

[408] TXU Exhibit 16, attachment BMG-3 at 14 of 17, paragraph 6 (Bates stamped page 39).

[409] Dallas Reply Brief at 28 (Mar. 17, 2004); TXU Exhibit 16, attach BMG-3 at 14 of 17, paragraph 6.

[410] Dallas Reply Brief at 28 (Mar. 17, 2004).

[411] TXU Exhibit 29 at 10-11.

[412] TXU Exhibit 29 at 10-11; Dallas reply Brief at 28 - 29.

[413] ATM Initial Brief at 57; Dallas Exhibit 2, attach DJL-3 at 2; ACC Exhibit 1, attachment EB-1(D) at 2.

[414] TUC §104.055; TXU Exhibit 16 at 15; TXU Exhibit 29 at 18.

recommend the Commission approve $24,363,004 annual amount in TXU's cost of service for reasonable expense incurred for the SLA.

The Examiners considered ACC's recommendation that TXU Gas be required to file with the Commission on a quarterly basis the actual performance of TXU Energy for each Customer Service Metrics. The Examiners recommend that TXU provide a quarterly report to the Commission showing the actual performance of TXU Energy for each measure listed in the SLA, Exhibit A entitled *Customer Care Metrics*. The information should be provided using a monthly breakdown and should be presented in a manner to enable the Commission to determine whether an adjustment to the SLA level would be appropriate on a forward-going basis.

The Examiners also considered TXU's argument that the price paid by TXU Gas under the SLA was no higher than the price charged by TXU Energy to other entities for the same type of services because TXU Energy does not provide the same billing and customer care services as those provided under the SLA to any other affiliate or third party. The Examiners did not find evidence to refute TXU's presumption. It is true that TXU Energy does not provide the *same* billing and customer care services to other affiliates or third parties. However, the intent of the TUC §104.055(b) requirement is to assure that gas utility ratepayers are charged a fair price in an affiliate transaction. The Examiners recommend that TXU be required to affirm that TXU Energy does not provide *similar* billing and customer care services to other affiliates or third parties and at its next rate case before the Commission to present additional information showing that the price charged by TXU Energy to TXU Gas for the services under the SLA is competitive.

TXU reported that the service levels set forth in the SLA are not only reasonable, they are excellent service levels for TXU Gas.[415] TXU also argued that the amount TXU Gas paid for the SLA services during the test year was reasonable, and was financially an excellent deal for TXU Gas.[416] TXU witness Gillespie provided TXU Exhibit 29, attachment BMG-R-5, TXU Energy Total Gas and Electric Customer Care Headcount (Jan. 2002 - Nov. 2003), and testified that the total number of all FTEs supporting TXU Gas and TXU Energy increased by four percent from the beginning of the test year 2002 through the end of November 2003.[417] The Examiners do not disagree that 914 to 950 is an approximate four percent increase. However, the great weight of the evidence presented does not support TXU's testimony. Instead, the record evidence shows that the number of customer care FTEs for TXU Gas actually declined during that time, and the quality of the customer care declined, while the fixed cost of the SLA remained constant.[418]

TXU witness Gillespie testified that he provided the information that intervening parties requested;[419] however, the evidence in the record shows that TXU was not forthcoming with discovery responses to the requests for information. The record lacks credible evidence showing why TXU did not disclose relevant information, such as the source of data, and did not timely disclose external FTE numbers. TXU's explanations are not credible or probative that it believed that the intervening parties' RFIs were specifically for call centers managed by TXU Energy and that outsource vendors are not managed by TXU Energy; or that TXU considered there to be a difference between managing a call center, using an

[415] TXU Exhibit 16 at 15.
[416] Tr. Vol. 4 at 101.
[417] TXU Exhibit 29, attachment BMG-R-5.
[418] ACC Exhibit 4 at 23a-24; ACC Exhibit4, Appendix E; TXU Exhibit 16, attach BWG-3 at 12 of 17.
[419] Tr. Vol. 9 at 139, lines 15-16.

outsource vender, and managing an outsource vender's call center.[420] Being distracted during a conference call is not credible, probative, or meaningful evidence of a genuine misunderstanding of the discovery request.[421] The evidence shows that it was appropriate for intervening parties to rely on the data that were provided by TXU. Further, those data do not support TXU's position that FTE numbers relating to gas services were increasing.

The evidence shows that TXU provided incomplete information in response to Dallas's and ACC's discovery requests. It is reasonable, given the circumstances described in the record, for these two intervening parties to have requested proof of the legitimacy of the underlying support upon which TXU based its decisions. TXU did not solicit bids for the provision of customer care services.[422] Instead, TXU relied upon the knowledge and experience of its witness, Mr. Gillespie, President of Destination Excellence. Destination Excellence provides consulting services relating to customer care.[423] Mr. Gillespie, however, had negotiated only one other contract involving a regulated utility. In that negotiation, Mr. Gillespie represented the interests of Utilipro, the firm for which Mr. Gillespie worked at that time and to which services would be outsourced. In the hearing, Mr. Gillespie explained that he had market research and bids provided by his company to determine the appropriate costs of the SLA terms. However, the intervening parties were not given access to the information that formed the basis of Mr. Gillespie's analysis.[424]

As well, the comparative analysis relied upon by Mr. Gillespie to make his recommendations to TXU Gas was not available to the intervening parties for review, due to existing non-disclosure agreements.[425] Instead of providing verifiable information, data, or market research to support its position, TXU Gas offered the testimony of Mr. Gillespie, his knowledge, and his experience. The Examiners did not find TXU's testimony to be credible, meaningful, or probative. When given an opportunity at the hearing to provide supporting documentation and the sources of his data, Mr. Gillespie for the first time provided some minimal basis for his decisions. However, the evidence provided was little more than an recitation of his experience and knowledge, not the factual data specific to TXU's operations.[426]

The great weight of the evidence shows that TXU did not supplement its RFI responses to the intervening parties to provide the number of external FTEs or to reveal the source of the data.[427] The evidence also shows that TXU was reluctant to provide to the intervening parties information relating to the identity of the outsource vendor and the numbers of outsource vendor employees, even though this information was relevant to customer care call center under the SLA.[428] The evidence shows that TXU Energy uses more outsource employees now than at the time the SLA was negotiated and, but for the collections group, those outsource employees are dedicated to TXU Energy's work rather than to TXU Gas' work.[429]

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420 Tr. Vol. 9 at 72, 151.
421 Tr. Vol. 9 at 192-193.
422 TXU Exhibit 16 at 12-14; ACC Exhibit 4 at 20; Tr. 4 at 60.
423 Tr. Vol. 4 at 59-60.
424 Tr. Vol. 4 at 61.
425 ACC Exhibit 4 at 19-20;
426 Tr. 4 at 60-73, for specific examples, see Tr. Vol. 4 at 61, Line 14-17; Tr. Vol. 4 at 66, Lines 12-14; Tr. Vol. 4 at 71, Lines 18-72.
427 Tr. Vol. 9 at 141, 149-150 .
428 Tr. Vol. 9 at 138 - 141.
429 Tr. Vol. 9 at 175.

For these reasons, the Examiners recommend the Commission reduce TXU's requested cost of service, and approve $24,363,004 as reasonable annual Service Level Agreement costs, including billing and customer care.

3. Other Affiliate Transactions: Oncor Electric, Receivables and Vermont Insurance Co.

<u>*Issue Summary*</u>

TXU Gas has additional affiliate transactions with Oncor Electric Delivery Company, L.P.(Oncor Electric); TXU Receivables Company; and TXU Vermont Insurance Company (TXU Vermont).

Oncor Electric Delivery Company, L.P.(Oncor Electric) - Personnel of Oncor Electric perform operations support services for TXU Distribution, including reading customer meters, design and engineering of certain construction projects, certain operating activities, developing and maintaining community and municipal relations, and managing certain business and economic development programs.[430] The operating and maintenance (O&M) expense associated with these activities is assigned based on timekeeping, through application of appropriate cost causation principles, or are directly charged to TXU Distribution.[431] This section addresses the Automated Timekeeping System (ATS), Meter Reading Service (MRS), and Other Transactions with TXU Electric. This issue is different from the Oncor Logo issue relating to uniforms and trucks, addressed in the Expenses section of this PFD.

TXU Receivables– Certain subsidiaries of TXU Corp. sell customer accounts receivable to TXU Receivables Company, a wholly-owned bankruptcy remote subsidiary of TXU Gas, which sells undivided interests in accounts receivable it purchases to financial institutions. During the test year ended December 31, 2002, TXU Energy Retail Company LP, TXU SESCO Energy Services Company, Oncor Electric, and TXU Gas Company were qualified originators of accounts receivable under the program. TXU Receivables Company may sell up to an aggregate of $600 million in undivided interests in the receivables purchased from the originators under the program.

TXU Vermont Insurance Company– TXU Vermont Insurance Company (TXU Vermont) is a wholly-owned single-parent captive insurance company responsible for providing varying levels of insurance coverage for certain TXU Corp. subsidiaries, including TXU Gas.[432] The lines of insurance written by TXU Vermont Insurance Company consist of third-party liability (i.e., general liability, auto liability, and errors/omissions), property/boiler and machinery, and executive assigned vehicles. In addition, TXU Vermont Insurance Company has been used to access the commercial reinsurance market to which the subsidiaries of TXU Corp. would not otherwise have access.

<u>*TXU's Position*</u>

TXU argued that affiliate transactions with Oncor Electric Delivery Company, L.P.(Oncor Electric) are proper. These transactions include the Automated Timekeeping System (ATS), Meter Reading Service (MRS), and other costs charged from Oncor Electric. TXU argued that by assigning shared costs on either

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[430] TXU Exhibit 17 at 10-11.
[431] TXU Exhibit 17 at 10-12.
[432] TXU Exhibit 15 at 32; TXU Exhibit 15, attachment SNR-4.

a per unit basis, or through time-keeping systems, only actual costs are charged, and no affiliate is charged a higher price than any other affiliate or third party for the same item or class of items.[433] TXU also argued that all services performed by Oncor Electric for TXU Distribution are billed at actual cost, with no profit or margin included in, or added to, the billings.[434] TXU concluded that all charges from Oncor Electric to TXU Distribution for shared services meet the requirements of TUC §104.055, that no intervening party challenged these costs, and that there is no evidence in the record to the contrary.[435]

Automated Timekeeping System (ATS)-- TXU described the Automated Timekeeping System (ATS) as a computerized time reporting application that is integrated into TXU's financial accounting system.[436] TXU reported that ATS is used by Oncor Electric employees to record actual time worked on certain gas and electric projects. Recorded time serves as the basis to equitably charge operations support service costs. During the test year, TXU reported that total O&M costs that Oncor Electric charged through the ATS process to TXU Distribution were approximately $7.4 million.[437]

TXU reported that ATS methodology was approved by the Commission in GUD 9145 and no intervening party in GUD 9400 challenged its use. TXU argued that the record evidence in this proceeding and Commission precedent supports a finding that the ATS methodology is an appropriate methodology for assigning costs for operations support services from Oncor Electric to TXU Distribution. TXU also argued the record evidence supports a finding that each item or class of items charged to TXU Distribution by Oncor Electric through ATS is reasonable and necessary and the charges assigned through ATS from Oncor Electric to TXU Gas are not higher than the prices charged by Oncor Electric to its other affiliates or to non-affiliated persons for the same items or class of items.[438]

Meter Reading Service (MRS)-- TXU described the Meter Reading Service (MRS) as a process incorporated into Oncor Electric's financial accounting system that is used to equitably assign costs for meter reading activities incurred by Oncor Electric for work performed for both electric and gas operations based on numbers of hours worked. The costs to provide meter reading services for electric and gas customers are allocated based on the number of hours actually required to read electric and gas meters each month as determined based on data compiled by electronic meter reading devices. During the test year, the total O&M costs for meter reading, customer re-read, and customer contact services that Oncor Electric charged through the MRS process to TXU Distribution was approximately $9.9 million.[439]

TXU argued that the MRS methodology is the appropriate methodology for the assignment of costs relating to meter reading activities between Oncor Electric and Distribution. For meter reading, the hours required to read gas and electric meters is the most appropriate basis to charge shared meter reading costs to the electric and gas customers.[440] The Oncor Electric costs that are assigned to TXU Distribution through the MRS process are reasonable and necessary and are based on the actual costs incurred in providing such

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[433] TXU Exhibit 17 at 10-12.
[434] TXU Exhibit 17 at 10-13.
[435] TXU Initial Brief at 101.
[436] TXU Exhibit 17 at 13.
[437] TXU Exhibit 17 at 14.
[438] TXU Exhibit 17 at 15.
[439] TXU Exhibit 17 at 16.
[440] TXU Exhibit 17 at 16-17.

services and are no higher than charges to a third party or other affiliate for the same or similar services. TXU noted that no intervening party challenged the MRS methodology or the costs that were assigned. Therefore, all of the record evidence in this proceeding, as well as Commission precedent, supports a finding that the MRS system is an appropriate methodology for assigning costs of meter reading from Oncor Electric to TXU Distribution.

Other Transactions with TXU Electric– TXU identified other costs charged from Oncor Electric to TXU Distribution including shared costs for common Company management, financial planning, human resources and common office facilities and equipment.[441] TXU reported that the accounting system accumulates expenses associated with these activities and assigns an equitable portion of these costs directly to TXU Gas. These types of costs are assigned to all affiliates of Oncor Electric that consume these services so that each affiliate pays the same amount on a per unit basis for the same item or class of items. TXU also argued that Oncor Electric owns and leases facilities that are shared with TXU Gas. Oncor Electric charges TXU Gas for an equitable portion of these shared facilities costs, based on square footage utilization. During the test year, the total O&M costs that Oncor Electric charged for these other affiliate transactions to TXU Gas was approximately $4.8 million.[442]

TXU argued that the services provided by Oncor Electric and the methodologies used for the assignment of such costs between Oncor Electric and TXU Gas are reasonable and necessary. The costs assigned to TXU Gas are based on the actual costs incurred in providing such services and are no higher than charges to a third party or other affiliate for the same or similar service. No intervening party challenged these methodologies or assigned costs. TXU argued that the record evidence in this proceeding supports a finding that these other costs assigned from Oncor Electric to TXU Gas are appropriate.

TXU Receivables– TXU argued that affiliate transactions with TXU Receivables are proper. Certain subsidiaries of TXU Corp. sell customer accounts receivable to TXU Receivables Company, a wholly-owned bankruptcy remote subsidiary of TXU Gas, which sells undivided interests in accounts receivable it purchases to financial institutions. During the test year ended December 31, 2002, TXU Energy Retail Company LP, TXU SESCO Energy Services Company, Oncor Electric, and TXU Gas Company were qualified originators of accounts receivable under the program. TXU Receivables Company may sell up to an aggregate of $600 million in undivided interests in the receivables purchased from the originators under the program.[443]

TXU argued that the TXU Corp. subsidiaries participating in the TXU Receivables program benefit in at least three ways. First, cash inflows related to customer accounts receivable are expedited, thereby reducing the level of cash working capital required by each participant. Second, the accounts receivable program provides for a lower cost source of funds. Finally, by selling these receivables, as opposed to factoring or borrowing against the receivables, these subsidiaries do not incur additional debt on their balance sheets to fund their cash working capital needs and are able to maintain a better debt rating than they might otherwise have.[444]

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[441] TXU Exhibit 17 at 17.
[442] TXU Initial Brief 102-103 (Mar. 8, 2004).
[443] TXU Exhibit 15 at 30.
[444] TXU Exhibit 15 at 30.

TXU stated that costs charged by TXU Receivables Company to the participants in this program include: (1) the fees (including interest and program fees) paid by TXU Receivables Company to the financial institutions purchasing the receivables, (2) general and administrative costs incurred by TXU Receivables Company to manage the program, (3) payment processing fees charged to TXU Receivables Company by TXU Business Services, and (4) a margin of approximately $5,000 per month charged by TXU Receivables Company. This margin is a necessary factor that establishes TXU Receivables Company as a bankruptcy remote entity, which allows the program to maintain its "sale" status for accounting treatment versus a debt-financing program.[445]

TXU explained that costs were assigned to each participant that was in this program during the test year. The fees charged by the financial institutions, the general and administrative costs incurred by TXU Receivables Company, and the margin discussed above are assigned to the participants of this program based on their relative share of sellable accounts receivable as a percent of the total amount of sellable receivables for all participants. The payment processing fees are assigned to each participant based on the number of payments processed on behalf of each participant. The amount billed by TXU Receivables Company during the 2002 test year to TXU Distribution was $1,144,866.21 and to Pipeline was $166, 913.78.[446]

TXU argued that the these costs charged by TXU Receivables Company to TXU Gas were for services that are necessary in the normal course of business, reasonably reflected the actual cost of these services, and were no higher than the prices charged to other participants in this program for the same service.[447]

TXU Vermont Insurance Company (TXU Vermont) -- TXU argued that affiliate transactions with TXU Vermont Insurance Company (TXU Vermont) are proper. TXU Vermont is a wholly-owned single-parent captive insurance company responsible for providing varying levels of insurance coverage for certain TXU Corp. subsidiaries, including TXU Gas. The lines of insurance written by TXU Vermont Insurance Company consist of third-party liability (i.e., general liability, auto liability, and errors/omissions), property/boiler and machinery, and executive assigned vehicles. In addition, TXU Vermont has been used to access the commercial reinsurance market to which the subsidiaries of TXU Corp. would not otherwise have access.[448]

TXU argued that the primary benefit realized by utilizing a captive insurance company such as TXU Vermont is the ability to establish an insurance deductible level appropriate for the corporation as a whole while minimizing the impact of that deductible expense on the financials of the business units compared to their using individually appropriate deductible levels. TXU Vermont has been used to access the commercial reinsurance market to which the subsidiaries of TXU Corp. would not otherwise have access.

TXU explained that general liability premiums were assigned based on revenues, employee count, 10 years of loss history, a deductibility/policy limit factor, and a catastrophic factor (i.e., determination based on experience of how likely a type of business is to have a loss and how often and how severe those losses

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[445] TXU Exhibit 15 at 30-31.
[446] TXU Exhibit 15 at 31; TXU Exhibit 15, attachment SNR-3.
[447] TXU Exhibit 15 at 31.
[448] TXU Exhibit 15 at 32-33.

are likely to be). Auto liability premiums were assigned based on vehicle count, 10-year loss history, and a deductible/policy limit consideration for each business unit. A portion of the errors and omissions premiums was assigned equally to all participants. The remaining portion was assigned based on a 10-year loss history and the general liability percentages. Property/boiler and machinery premiums are assigned based on replacement cost values, 10-year loss history, and a deductible/limit factor. Executive assigned vehicles premiums were assigned based on the number of assigned vehicles and a 10-year loss history. The premiums billed by TXU Vermont during the 2002 test year ended were listed in TXU Exhibit 15, attachment SNR-4. TXU Vermont billed $2,473,598 to TXU Distribution, and $248,626 to Pipeline.

TXU argued that the premiums charged to TXU Gas were for services that are necessary in the normal course of its respective business, reasonably reflected the actual cost of these services to these entities, and were no higher than the prices charged to other participants in this program for the same service.[449]

TXU disagreed with Dallas's recommendations to reduce Account 925, Injuries and Damage, due to the fluctuations of payments over the last four years for TXU Vermont.[450] TXU argued that Dallas used the charges from TXU Vermont in the four-year average on which it based its proposed normalization adjustment to Injuries and Damages expense.[451] TXU explained that Dallas's four-year adjustment included the year 1999, a year in which TXU Vermont charged no premiums to TXU Gas because in that year TXU had sufficient loss reserves. TXU argued that Dallas's proposed adjustment was a piecemeal and self-serving ratemaking approach.[452]

Intervening Parities' Positions

Dallas argued that charges from TXU Vermont contributed to the varying injuries and damages expense experienced by TXU Gas over the four-year period that ended December 31, 2002.[453] Dallas argued that the expense paid to TXU Vermont varied for many reasons, including premium credit due to lower loss expected in 1999 from TXU's wholly owned captive insurance company, reduction due to settlement of claims in 2001, and increase in premiums and claims in 2002. Dallas argued that injuries and damages was increased in the four years, due in part to expense paid to the TXU Vermont Insurance. Based on a four-year average, Dallas recommended a total injuries and damages expense reduction of $4,082,183 for Distribution and $481,987 downward adjustment for Pipeline.

Examiners' Recommendation

The Examiners recommend that the expenditures proposed by TXU for affiliate transactions with Oncor Electric Delivery Company, L.P. (Oncor Electric), TXU Receivables Company (TXU Receivables); and TXU Vermont Insurance Company (TXU Vermont) be approved. TXU described the expenditures and billing methodologies used by each affiliate. The Examiners did not find that the evidence presented by the intervening parties contravened TXU's presentation regarding affiliate transactions. The Examiners find that TXU demonstrated that its affiliate expenditures are reasonable and necessary. TXU demonstrated that the price charged by Oncor Electric, TXU Receivables, and TXU Vermont are not higher than the prices charged to other affiliates or to non-affiliated persons. The Examiners recommendation

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[449] TXU Exhibit 15 at 16-17, 29-33.

[450] TXU Exhibit 28 at 54.

[451] TXU Exhibit 28 at 55.

[452] TXU Initial Brief at 114-115.

[453] Dallas Exhibit 1 at 39-40 (Mar. 8, 2004).

is consistent with Commission decision in GUD 9145.

VI. RATE BASE

Rate base is the utility's invested capital. TUC §104.053 provides that rate base is the adjusted value of invested capital. Invested capital is the original cost of plant at the time it became used and useful in the service of gas service, less the amounts of depreciation. Rate base is calculated as a reasonable balance between (1) original cost less depreciation ands (2) current cost, less an adjustment for the plant's present age and condition. For consistency with TUC §104.051, the Commission determines the utility's overall revenues at an amount that will permit the utility to earn a reasonable opportunity to earn a reasonable return on the utility's invested capital. In other words, rate base is the amount upon which the utility requests to earn a return. Evaluation of rate base uses asset balances during a test year. The rate base is then adjusted higher or lower based on known and measurable changes.

A. Invested Capital/Rate Base

1. Original Cost

TXU Exhibits 6, 7, and 61, Schedules B(D) and B(P), indicated that the original cost in the invested capital rate base, as adjusted, was $1,337,555,664. TXU sought Commission approval for this amount as the combined invested capital rate base for both Pipeline and Distribution.[454]

2. Completed Construction Not Classified

<u>*Issue Summary*</u>
In GUD 9400, TXU's test year ended December 31, 2002. By March 31, 2003, TXU completed Distribution and Pipeline projects that had been under construction as of December 31, 2002. TXU proposed to include these projects in rate base as completed construction not classified (CCNC). When utility plant is put into service and is used and useful, a utility may incorporate the plant into its proposed rate base, as a known change. However, when a utility proposes to adjust its rate base upward to account for plant that became used and useful at a time beyond the test year, the utility must also account for the related decreases in rate base.

<u>*TXU's Position*</u>
TXU included completed construction not classified (CCNC) in its proposed rate base.[455] TXU defined CCNC as plant that was in service after the test year that TXU included as a known and measurable change to the test year data.[456] The test year concluded on December 31, 2002; however, the CCNC sought by TXU is for the cost of projects under construction as of December 31, 2002, that were completed by March 31, 2003.[457]

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[454] TXU Initial Brief at 12 (Mar. 8, 2004).
[455] TXU Exhibit 14 at 5, 6.
[456] TXU Exhibit 27 at 10.
[457] TXU Exhibit 61, Schedule C-1(D) at 1, line 18; Schedule C-1(P) at 1, line 44.

As justification for inclusion of CCNC in rate base, TXU noted that the Commission approved the inclusion of CCNC in rate base in two prior Commission proceedings, GUD Nos. 8664 and 9145.[458] TXU also argued that inclusion of CCNC in rate base is consistent with the Commission's Natural Gas Rate Review Handbook.[459] TXU included $5,912,729.61 of CCNC in the original cost of Distribution utility plant.[460] TXU included $2,600,248.39 of CCNC in the original cost of Pipeline utility plant.[461]

Intervenor's Positions

ACC recommended that CCNC placed in service subsequent to the end of the test year be disallowed because TXU failed to match any additional revenue or expense related to the particular CCNC.[462] ACC also disputed whether TXU's treatment of CCNC is consistent with the Commission's Natural Gas Rate Review Handbook.[463]

ATM opposed TXU's proposed inclusion of CCNC.[464] ATM noted that TXU had not matched inclusion of CCNC with increases in accumulated depreciation nor with accumulated deferred income taxes.[465] ATM argued that adjusting balances of accumulated depreciation and accumulated deferred income taxes to include the first three months of 2003 more than offset TXU's proposed inclusion of CCNC.[466] In ATM's estimation, Distribution rate base would be reduced by approximately $13.275 million, and Pipeline rate base by $3.147 million, if accumulated depreciation and accumulated deferred income taxes were properly tabulated through March 2003.[467]

Dallas also noted that inclusion of CCNC in rate base without accounting for reductions to rate base due to accrued depreciation expense would be inappropriate.[468] Dallas recommended eliminating TXU's proposed CCNC from rate base, or alternatively, recognizing an increase in accumulated provision for depreciation of $13,241,885 for Distribution plant and an increase of $3,965,580 for Pipeline plant.[469]

Commission Staff

Staff of the Railroad Commission noted that TXU misquoted the Commission's Natural Gas Rate Review Handbook with respect to treatment of CCNC. Staff recommended that rather than addressing post-test-year plant addition in this proceeding, TXU should consider seeking inclusion of CCNC under TUC §104.301 relating to Interim Cost Recovery and Rate Adjustments.[470]

Examiners' Recommendation

The Examiners recommend the Commission disallow TXU's proposal to include in invested capital plant

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[458] TXU Exhibit 27 at 11.
[459] TXU Initial Brief at 13 (Mar. 8, 2004).
[460] TXU Exhibit 61, Schedule C-1(D) at 1, line 18.
[461] TXU Exhibit 61, Schedule C-1(P) at 1, line 44.
[462] ACC Exhibit 3 at 8.
[463] ACC Reply Brief at 15-16 (Mar. 17, 2004).
[464] ATM Exhibit 1 at 9; ATM Initial Brief at 23 (March 8, 2004).
[465] ATM Exhibit 1 at 9.
[466] ATM Exhibit 1 at 10.
[467] ATM Exhibit 1at 10.
[468] Dallas Exhibit 1at 90.
[469] Dallas Exhibit 1at 91.
[470] Staff's Reply Brief at 5 (March 17, 2004).

that it booked to the completed construction not classified (CCNC) account. The Examiners find that the plant that TXU characterized as CCNC was construction work in progress (CWIP) on December 31, 2002, the test year-end date for setting rates in this proceeding. TXU failed to present persuasive evidence clearly demonstrating that the $5,912,729.61 of Distribution utility plant and $2,600,248.39 of Pipeline utility plant that was CWIP on December 31, 2002, was actually in service, used and useful, by March 31, 2003, the date selected by TXU for including post-test year adjustments to rate base to reflect known changes to asset balances. Even if TXU had shown this plant to be used and useful, TXU failed to adjust revenues and expenses to reflect the presence of this plant in rate base.

The test year-end date for setting rates in this proceeding is December 31, 2002. However, TXU sought to include in rate base $5,912,729.61 of Distribution utility plant and $2,600,248.39 of Pipeline utility plant that had been CWIP on December 31, 2002.[471] TXU characterized this plant not as CWIP, but rather as CCNC. The Examiners note that a gas utility may be permitted to include CWIP in its rate base only where necessary to the financial integrity of the utility.[472] TXU has made no request to include CWIP in rate base, and has stated that it did not include CWIP in its calculation of rate base.[473] The evidence shows that TXU did not propose to include CCNC on the basis of the need for financial integrity.[474]

TXU's witness Mr. Dane Watson stated in his direct testimony that CCNC reflected construction projects completed by March 31, 2003.[475] However, TUC §104.051 makes clear that in establishing a gas utility's rates, the Commission must establish the utility's revenues based on "the utility's invested capital used and useful in providing service to the public."[476] In other words, completion of a project is not sufficient for inclusion of that project in rate base; the project must be used and useful in providing service to the public before it may be included in rate base. Although Mr. Watson’s rebuttal testimony stated that CCNC represented plant that was in service after the test year, TXU's Schedule C-1(D) again indicated that, at least with respect to Distribution utility plant booked as CCNC, these projects were simply completed by March 31, 2003.[477] The Examiners find that TXU did not provide evidence demonstrating that the plant booked as CCNC was used and useful in providing service to the public. Even if TXU showed that all the plant booked by TXU as CCNC was used and useful by March 31, 2003, inclusion of that plant in rate base is problematic because TXU failed to account for the impact of the resultant expenses and revenues on rate base.

The "matching principle" is a well-established fundamental principle of accounting and ratemaking. It requires expenses to be reported in the same period as the revenues resulting from those expenses. Here, TXU included CCNC in rate base after the end of the test year. Expenses and revenues attached to that plant, and have not been accounted for by TXU. For example, TXU made no attempt to ascertain the increased revenue from the inclusion of this plant.[478] Nor did TXU adjust its accumulated depreciation

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[471] TXU Exhibit 61, Schedule C-1(D) at 1, line 18; Schedule C-1(P) at 1, line 44.
[472] 16 TEX. ADMIN. CODE §7.5212 (2002).
[473] TXU Exhibit 14 at 5.
[474] ATM Initial Brief at 24; Dallas Initial Brief at 18.
[475] TXU Exhibit 14 at 5, 6.
[476] TUC §104.051 (Vernon 1998 and Supp. 2004).
[477] TXU Exhibit 27 at 10; TXU Exhibit 61, Schedule C-1(D) at 1, line 18.
[478] ATM Exhibit 1at 11.

of utility plant resulting from inclusion of CCNC in rate base.[479] The Examiners find that not accounting for such items leads to inaccurate conclusions about TXU's financial situation.

TXU pointed to Findings of Fact 27 and 28 in the final order of GUD 8664 as evidence that the Commission has previously allowed the inclusion of CCNC in rate base.[480] Findings of Fact 27 and 28 do not, however, make clear that they address CCNC. Assuming that they do, however, the most noticeable difference between that docket and the instant one is the dollar amount at issue. Findings of Fact 27 and 28 concern a total of $133,389. In this proceeding, TXU seeks to include $5,912,729.61 in Distribution utility plant and $2,600,248.39 in Pipeline utility plant as CCNC. The Examiners find that the dollar amounts at issue in this proceeding are too large to merit inclusion of CCNC in rate base, without additional information relating to the revenues and expenses associated with that plant.

TXU also pointed to Schedule H-1 in the final order in GUD 9145-9148 as evidence that the Commission allowed for CCNC in prior rate cases.[481] Schedule H-1 is a depreciation expense schedule that shows that $63,726 of depreciation expense was attributed to "completed not classified" Distribution plant, and $603,891 of Distribution expense was attributed to "completed not classified" general plant. However, the Examiners find no reference to CCNC in the Order to ascertain the amount of CCNC included in rate base nor a rationale for its inclusion as a line item in Schedule H-1.

The Examiners find that the plant booked to CCNC should not be included in rate base in the current proceeding because it was not used and useful as of the end of the test year and because TXU did not account for known changes affecting rate base by its decision to include CCNC in rate base. However, the Examiners note that TUC §104.301 (SB 1271, 78th Reg. Leg. Session) provides gas utilities an opportunity to file a tariff or rate schedule for interim adjustments in the utility's monthly customer charge or initial block rate to recover the cost of changes in the investment in service for gas utility services, without the necessity of a full ratemaking proceeding.[482] Therefore, TXU has a vehicle to adjust rates to reflect changes in the value of invested capital resulting from the used and useful service of CCNC plant.

Finally, the Examiners note that TXU misquotes the Commission's Natural Gas Rate Review Handbook.[483] In fact, the handbook states that "[t]he present practice of the Commission is to use asset balances as of the test year end adjusted for known changes, as opposed to the average balance for the test year, because year end data more accurately represents existing conditions on which to base rates for the future."[484] CCNC is not expressly identified as an item that qualifies as a "known change" that merits amending test year data. However, if TXU is going to include CCNC as a known change to test year data, TXU must account for other known changes that result from inclusion of CCNC. Such an approach to addressing post-test year known changes would be most consistent with the Handbook.

For these reasons, the Examiners recommend that the original cost of Distribution utility plant be reduced in the amount of $5,912,729.61, and that the original cost of the Pipeline utility plant be reduced by

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[479] TXU Exhibit 61, Schedule D-1(D) at 1; Schedule D-1Revised (P) at 1.
[480] TXU Exhibit 27 at 11.
[481] TXU Exhibit 27 at 11.
[482] TUC §104.301 (Vernon 1998 and Supp. 2004).
[483] TXU Exhibit 27 at 9.
[484] Railroad Commission of Texas, *Natural Gas Rate Review Handbook* (November 1999) at 15.

$2,600,248.39. Disallowance of TXU's proposed inclusion of CCNC in invested capital will require that a depreciation expense reduction be made.

The Examiners recommend further modification to Pipeline rate base be considered. TXU, in addition to proposing inclusion of CCNC in Pipeline rate base, also proposed reducing Pipeline rate base to account for the sale of the Streetman and Teague Pipeline properties in March and April of 2003.[485] Specifically, TXU proposed to reduce the original cost of Pipeline utility plant by $3,367,402.95 to account for the sale of these properties.[486] To be consistent with its decision to disallow post-test year CCNC and in consideration of the matching principle discussed above, the Examiners further recommend that the original cost of Pipeline utility plant be increased by $3,367,402.95. As was discussed above, TXU may, at its discretion, at a later date, file with the Commission an application in accordance with TUC §104.301 to account for this post-test year sale of plant. Adding the Streetman and Teague facilities back to invested capital will require that a depreciation expense increase be made.

3. Streetman and Teague Gathering Systems /Gains from Sales

Issue Overview

TXU Gas proposed an adjustment to its Pipeline rate base to remove the Streetman and Teague facilities that were sold in March and April 2003.[487] In the section on Completed Construction Not Classified (CCNC), the Examiners recommended the Commission disallow TXU's proposal to include in invested capital plant that it booked to the completed construction not classified (CCNC) account. TXU proposed other post-test-year accountings. TXU had proposed to reduce the original cost of Pipeline utility plant by $3,367,402.95 to account for the sale of these properties of the Streetman and Teague Pipeline properties in March and April of 2003.[488] For consistency with the other post-test-year adjustments, the Examiners recommend the Commission disallow TXU's proposed adjustment, thereby increasing the original cost of Pipeline utility plant by $3,367,402.95. TXU may file with the Commission an application in accordance with TUC §104.301 to account for this post-test year sale of plant.

TXU's Position

TXU provided argument relating to the sales of the Teague and Streetman facilities in its March 8, 2004, Initial Brief and its March 17, 2004, Reply Brief.

TXU argued that it made reasonable adjustments to its Pipeline invested capital to remove the Streetman and Teague facilities that were sold by TXU in March and April, 2003.[489] TXU argued that ACC's recommendation -- to include gross (rather than net) sales proceeds associated with the sale of the Teague and Streetman Pipeline properties as an offset to TXU Pipeline's invested capital-- was inappropriate. TXU argued that ACC's proposal fails to recognize that the sales costs associated with the Teague and Streetman properties must be netted against the proceeds of the sales.

TXU argued that its treatment of the sales proceeds of the Teague and Streetman properties was consistent

[485] TXU Exhibit 61, Schedule C-1(P) at 1; line 46; WP/C-1/1(P) at 1.
[486] TXU Exhibit 61, Schedule C-1(P) at 1; line 46; WP/C-1/1(P) at 1.
[487] TXU Exhibit 14 at 5.
[488] TXU Exhibit 61, Schedule C-1(P) at 1; line 46; WP/C-1/1(P) at 1.
[489] TXU Initial brief at 37 (Mar. 8, 2004).

with the NARUC Uniform System of Accounts, which requires sale proceeds to be netted against associated costs.[490] To support its position, TXU maintained that NARUC Plant Instruction 7E requires the sales proceeds that are booked to be "the amount received from the sale less agent's commissions and other costs incident to the sale."

ACC had argued that NARUC Plant Instruction 7E required TXU to receive Commission approval before costs associated with sales are deducted and booked in either Account 414 or 422.[491] TXU argued that ACC's statement is misleading because the sale of the Streetman and Teague facilities were booked in Account 108-Accumulated Provision of Depreciation of Utility Plant in Service, not Account 414 or 422.[492] ACC stated that the sales are properly included in Account 108 because they represent the retirement of depreciable utility plant in service. TXU argued that no party challenged the booking of the sales to Account 108. TXU stated that NARUC Plant Instruction 7E demonstrates that the sales were properly booked. TXU stated that support for its position that sales proceeds must be netted against the associated costs is found throughout the NARUC Uniform System of Accounts which defines "salvage value" as "the amount received for property retired, less any expenses incurred in connection with the sale of or in preparing the property for sale . . . ." TXU stated that NARUC Plant Instruction 10F provides that "the book cost less net salvage of depreciable utility plant retired shall be charged in its entirety to account 108 . . . ."

TXU argued that ACC's position – that the utility did not adequately support the costs that were netted against the sale proceeds-- was incorrect.[493] TXU relied upon ACC Exhibit 27 as its support, noting that the expenses incurred from the sale of the Streetman and Teague facilities including legal fees and an environmental insurance policy, should be netted against the proceeds of the sale.[494]

TXU also argued that it is unreasonable to expect the utility to continually update its cost of service filing beyond March 31, 2003, to reflect additional expenses incurred as a result of these sales.
TXU concluded that the pro forma adjustment reflects the known and measurable change associated with the sale of these assets. The period captured by the pro forma adjustment ended March 31, 2003.[495]

Intervening Parties' Positions

ACC noted that TXU had reduced the proceeds from the sales of the two facilities for expenses it incurred relating to the actual sale of the facilities. TXU had reduced the value of the proceeds for legal and insurance costs. ACC recommended that for application to the utility's plant-in-service, no amounts should be "netted" against the proceeds because those costs are not recurring. ACC also argued that the legal and insurance costs were not shown to be specifically applicable to the sale of the two facilities. ACC recommended an adjustment to reduce Pipeline plant in service by $86,273, to account for the proceeds that were received from the sales of the facilities.[496]

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[490] TXU Initial Brief at 37 (Mar. 8, 2004).
[491] ACC Initial Brief at 38 (Mar. 8, 2004).
[492] ACC Exhibit 27.
[493] ACC Initial Brief at 39-40 (Mar. 8, 2004).
[494] TXU Reply Brief at 38 (Mar. 17, 2004).
[495] TXU Reply Brief at 38 (Mar. 17, 2004).
[496] ACC Exhibit 3 at 18; ACC Initial Brief at 38-39; ACC Exhibit 101, attachment EB-4(P) at 2.

ACC argued that TXU should not be allowed to deduct costs without prior approval of the Commission and only after providing clear and convincing evidence that such costs were only related to the sale of the facilities. ACC noted that TXU had confirmed that the assets were no longer used and useful, had been removed from invested capital, but had not researched the legal fees that it argued were appropriately removed from the sales proceeds. ACC argued that TXU failed to state who had incurred the fees. ACC stated that TXU did not provide information to determine whether the costs were included in the determination of the allocation factors for affiliated transactions. ACC observed that TXU had relied upon NARUC Utility Plant Instruction 7E to support its treatment of the proceeds from the sales. ACC noted that Instruction 7E pertains to the sale of land and land rights, and was therefore not determinative of this particular issue. ACC argued that even if Instruction 7E were determinative of this issue, Instruction 7E also requires the approval of the Commission before the costs were to be properly deducted.[497]

ACC argued that TXU failed to provide any details, beyond the aggregate, for these expenses in spite of being requested for information concerning the costs that were applied against the sales proceeds. ACC argued that information was requested but not provided. ACC argued that no supplemental response to ACC Exhibit 27 was ever provided, that TXU testified that additional costs for the sale had been incurred, that TXU never included adequate information in this proceeding, and that none of these additional costs were included TXU's corrections to testimony. Therefore, ACC argued, TXU did not support its statements.[498]

Examiners' Recommendation

The Examiners affirm their recommendation that post-test-year adjustments be disallowed, including the sale proceeds of the Streetman and Teague Pipeline properties in March and April of 2003. The Examiners recommend the Commission disallow TXU's proposed adjustment, thereby increasing the original cost of Pipeline utility plant by $3,367,402.95. The post-test-year sales of Teague and Streetman can be considered at the same time as TXU's post-test-year plant addition, if TXU files an application at the Commission in accordance with TUC §104.301 to account for this post-test year sale of plant.

4. Accumulated Depreciation

While depreciation records the decline in service capacity of property over an asset's service life, the accumulated depreciation accounts for the cumulative depreciation costs that are recovered through rates. Accumulated depreciation is also called a depreciation reserve and represents the return of the investment. This on-going record of the deduction from rate base occurs to obtain the net investment. When a utility calculates its invested capital in accordance with TUC §104.053, one basis it considers is its original cost, less its accumulated depreciation. In this proceeding, accumulated depreciation issues include the accumulated depreciation associated with the vintage plant transferred between Pipeline and Distribution operations subsequent to June 1999 and ACC's half-year convention. In addition, Commission decisions regarding construction completed not classified, and treatment of Streetman and Teague may require modification of the accumulated deprecation reserve.

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[497] ACC Initial Brief at 38-39.

[498] ACC Initial Brief at 38-39; Tr. Vol.2 at 204 -209; Tr. Vol. 2 at 205-208; ACC Reply Brief at 33 (Mar. 17, 2004).

TXU's Position

Both Distribution invested capital and Pipeline invested capital are derived from the books and records of the utility and have been appropriately adjusted for known and measurable changes. TXU argued that the evidence established that TXU properly calculated accumulated depreciation for rate base in this proceeding. TXU reported that it calculated accumulated depreciation for rate base using the same methodology approved by the Commission in GUD 8664, 8976, and 9145-9148.[499] TXU argued that no basis exists for calculating accumulated depreciation any differently.

TXU based its accumulated depreciation on historic depreciation rates of the original cost of the facilities used to provide service to TXU Gas' customers. The accumulated depreciation associated with the vintage plant transferred between Pipeline and Distribution operations subsequent to June 1999 is one issue in this proceeding.

TXU addressed ACC's proposed application of a half-year convention adjustment to reduce the Distribution and Pipeline accumulated depreciation balances in invested capital by $2,834,316 and $393,432, respectively. TXU argued that ACC's proposal should be rejected because no accepted depreciation treatise condones the use of the half-year convention in the manner proposed by ACC. ACC's proposal would prevent TXU from ever earning a return on its investment, which would be reduced by an amount equal to a half year of future depreciation expense the moment the investment is made. Accordingly, this approach would result in the Commission disallowing a portion of TXU's investment.[500]

TXU did not agree with ACC's use of TUC §104.301 to support its proposal because the statute only allows the utility to recover net investment made since its last rate case filing and TUC §104.301(e) requires TXU to file an annual earnings monitoring report with the Commission. This report provides the Commission with a tool to determine whether to initiate a rate proceeding for over-earnings. Thus, TUC §104.301 actually negates the concerns that ACC cited in support of its proposal to moderate earnings by applying a half-year convention adjustment to reduce TXU's rate base.

TXU criticized ACC's position that its proposed adjustment would provide consistency between test year depreciation expense and the year-end rate base. ACC failed to explain how its adjustment would accomplish this result. ACC's failed to acknowledge that the effect of its adjustment would be to move the test year forward for only a single component of the cost of service, i.e., the depreciation expense on existing assets. TXU used ACC Exhibit 66 to illustrate that artificial manipulation will reduce the level of investment and prevent TXU from ever earning a return on its investment because investment is reduced by an amount equal to a half year of future depreciation expense the moment the investment is made. TXU gave the example that, under ACC's proposal, if TXU had $100 of investment and this investment was reduced to reflect a half year of future depreciation expense ($20), then the net investment on which rates are based is $80. This has the effect of disallowing $20 of the utility's prudent investment absent any evidentiary support and prevents TXU from ever earning a return of or on this $20 in investment. Such a result must be rejected as unsound, unsupported, and confiscatory.

TXU summarized its position, stating that ACC's proposed methodology is unsound; TXU properly

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[499] TXU Exhibit 27 at 9.

[500] TXU Exhibit 27 at 9 - 10; TXU Initial Brief at 16-17; TXU Reply Brief at 12-13.

calculated accumulated depreciation for rate base in this proceeding, using methodologies previously approved by the Commission. Therefore, the Commission should approve TXU's accumulated depreciation calculated in this case.[501]

ACC's Position

ACC argued that accumulated reserves for depreciation should be recalculated, resulting in a reduction of Distribution net plant in service in the amount of $2,834,316 and reduction in Distribution general plant in the amount of $15,277.[502]

ACC recommended that TXU's accumulated reserve for depreciation be adjusted using a regulatory half-year adjustment for consistency with the test year depreciation expense and the use of a year-end rate base. ACC argued that if this adjustment is not made, TXU will likely over-recover its authorized return on plant in service. ACC explained that the half-year convention is usually recommended for plant added during the test year, to recognize that the additional investment would have some depreciation during the future rate period. ACC argued that in other cases there would be several years between rate increases. Thus, the normal increases and decreases in plant in service amounts would level each other out over a period of time. However, when the rate cases are more frequent, or when a utility is able to update its investment amount without filing a rate case then a proper baseline amount must be set. ACC argued that TUC §104.301 allows TXU to update its investment without filing a rate case. ACC argued that the resulting impact on rate base is to reduce the total net Distribution plant in service by $2,834,316, and to reduce Distribution general plant by $15,277. [503]

ACC commented on TXU's statements that no treatise condones the use of the half-year convention in the manner proposed by ACC and that ACC's proposal would prevent TXU from ever earning a return on its investment. ACC responded that the Public Utility Commission of Texas has considered or used the half-year proposal in several utility dockets and that TXU misunderstood ACC's adjustment.[504]

ACC clarified TXU's understanding of its half-year convention. ACC argued that the example in ACC Exhibit 66 shows that without the adjustment, based only on the incremental increase in depreciation expense, TXU will not only receive all of the increase in depreciation expense as an expense item, but a higher than authorized return on the net plant -- because the increase in depreciation is not being recognized in the accumulated reserve or depreciation. ACC argued that without the adjustment, TXU benefits from the recovery of the principal investment (through depreciation) as well as a return on that principal as if it remained unrecovered by investors.[505]

ACC noted that if the Commission approved its half-year convention, an adjustment to the depreciation expense for construction completed not classified (CCNC) would be necessary. ACC argued that if CCNC were allowed, the Commission should require an adjustment to the accumulated reserve for depreciation to take into account the half-year adjustment to assure that no over-recovery of return is allowed on the

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501 TXU Exhibit 27 at 9 - 10; TXU Initial Brief at 16-17; TXU Reply Brief at 12-13.
502 ACC Initial Brief at 21-22.
503 ACC Initial Brief at 21-22.
504 ACC Reply brief at 18-19.
505 ACC Exhibit 66; ACC Initial Brief at 21-22; ACC Reply Brief at 18-19.

CCNC. ACC argued alternatively if the Commission were to disallow CCNC, then ACC' proposed adjustment to TXU's depreciation expense is appropriate.

Finally, ACC argued that if the Commission determined that the CCNC is appropriately included, but the depreciation expense should be adjusted by the one-half year method, then the CCNC depreciation expense should be added in to ACC's proposed depreciation expense with one-half of the expense amount added to depreciation reserves.[506]

ATM's Position

ATM argued against TXU's post-test-year inclusion of plant addition. ATM argued that if the Commission disallows TXU's proposed adjustments for post test year plant additions, the year-end depreciation reserve and year-end accumulated deferred income tax balances are proper. However, if the Commission were to allow TXU's proposed post-test-year plant additions through March 31, 2003, the depreciation reserve and the accumulated deferred income tax balances should also be adjusted to March 31, 2003 levels. Recognition of the matching change in the accumulated depreciation reserve and accumulated deferred income tax balances would reduce Distribution rate base by $13.275 million and Pipeline rate base by $3.147 million.[507]

Examiners' Recommendation

The Commission's decision on many issues in this proceeding will require associated adjustments to TXU's accumulated depreciation. In the section of this PFD relating to Depreciation, the Examiners recommended that the Commission reject ACC's proposed half-year adjustment in this proceeding because TXU properly calculated accumulated depreciation for its assets using the methodology previously approved in GUD 8664, 8976, and 9145-9148; and because the evidence presented by ACC was not probative that a half-year adjustment to TXU's depreciation reserve was necessary. For the same reasons, the Examiners affirm their recommendation relating to the half-year convention.

In the section of the PFD relating to Construction Completed Not Classified (CCNC), the Examiners recommended the Commission disallow TXU's proposed post-test-year plant addition. For the same reasons, the Examiners affirm their recommendation relating to CCNC. In that case, no adjustment to accumulated depreciation would be needed. However, the Examiners recommend the Commission require an adjustment to accumulated depreciation be implemented by TXU if the CCNC is allowed. Similarly, if the Commission agrees with the Examiners' recommendation to disallow TXU's post-test-year treatment of the Streetman and Teague facilities, an adjustment to accumulated depreciation would be necessary.

5. Inventory, Materials and Supplies, and Prepayments

TXU requested the Commission approve inclusion of materials and supplies inventory in its rate base calculations.[508] TXU proposed inclusion of $3,859,290 for materials and supplies in total rate base for TXU Gas – Distribution.[509] The utility proposed inclusion of $3,141,829 for materials and supplies in total

[506] ACC Initial Brief at 21-22.

[507] ATM Initial Brief at 23-25; ATM Reply Brief 12-13.

[508] TXU Exhibit 14 at 6.

[509] TXU Exhibit 61, Schedules B(D) and E-1(D).

rate base for TXU Gas – Pipeline.[510]

TXU also requested the Commission approve prepayments in its rate base calculations.[511] Generally, a prepayment is an amount paid in advance to a service or product supplier (for example, for insurance, undelivered gas, rent, etc.). TXU proposed inclusion of $11,911,827 for prepayments in total rate base for TXU Gas – Distribution.[512] TXU proposed inclusion of $760,368 for prepayments in total rate base for TXU Gas – Pipeline.[513]

Intervenor's Positions
No intervening party opposed TXU's proposal.

Examiners' Recommendation
The Examiners recommend the Commission approve inclusion of inventory and prepayments in rate base as reasonable and necessary.

6. Line Pack Gas

TXU requested the Commission approve inclusion of line pack gas in its rate base calculations.[514] Line pack gas is that gas necessary to maintain pressure in the pipeline to ensure an uninterrupted flow of natural gas at all times. TXU proposed inclusion of $2,506,634 for line pack gas in total rate base for TXU Gas – Pipeline.[515]

Intervening Parties' Positions
No intervening party opposed TXU's proposal.

Examiners' Recommendation
The Examiners recommend the Commission approve inclusion of line pack gas in rate base as both reasonable and necessary in amount and used and useful in providing utility service.

7. Cushion Gas

TXU's Position
TXU included an amount for Cushion Gas In Storage in its rate base calculations for TXU Gas - Pipeline.[516] Cushion gas is the gas that must be maintained in a reservoir used for the storage of natural gas; cushion gas ensures a reservoir pressure sufficient to ensure the recovery of the storage gas. TXU proposed inclusion of $18,021,864 for Cushion Gas In Storage in total rate base for TXU Gas – Pipeline.[517]

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[510] TXU Exhibit 61, Schedules B(P) and E-1(P).
[511] TXU Exhibit 14 at 6.
[512] TXU Exhibit 61, Schedules B(D) and E-2(D).
[513] TXU Exhibit 61, Schedules B(P) and E-2(P).
[514] TXU Exhibit 14 at 6.
[515] TXU Exhibit 61, Schedules B(P) and E-9(P).
[516] TXU Exhibit 61, Schedule E-10(P) and Schedule B(P).
[517] TXU Exhibit 61, Schedule E-10(P) and Schedule B(P).

Intervening Parties' Positions
No intervening party opposed TXU's proposal.

Examiners' Recommendation
The Examiners recommend the inclusion of TXU's requested amount for Cushion Gas In Storage in Pipeline rate base as reasonable and necessary and used and useful.

8. Working Gas in Storage/Working Gas Inventory

TXU's Position
TXU proposed to include $98,182,654 booked for Working Gas in Storage in the invested capital for TXU Gas - Distribution.[518] TXU stated that Working Gas in Storage is gas that is injected into storage and removed from storage in order to meet the gas supply needs of Distribution.[519] TXU argued that working gas inventory has been a TXU Gas - Distribution asset "since at least 1996 . . . and the return on that working gas has been a component of the gas cost charged by Distribution to residential and commercial sales customers since that time."[520]

Intervening Parties' Positions
ACC stated that working gas should not be included in the invested capital for Distribution.[521] ACC argued "that working gas inventory should continue to be a component of Pipeline related rate development as it has been in prior city gate cases before this Commission."[522] Dallas also opposed including Working Gas in Storage in Distribution rate base.[523] Dallas noted that "all storage assets are part of the Pipeline business and the gas stored in these facilities is more appropriately included in the Pipeline cost of service, not Distribution."[524] ATM supported ACC's and Dallas's position.[525]

Examiners' Recommendation
The Examiners recommend that $98,182,654 booked for Working Gas in Storage be included in the rate base for Pipeline and allocated entirely to the City Gate customer class. No party opposed the inclusion of Working Gas in Storage in the rate base of TXU Gas. No party opposed the dollar amount that TXU booked for Working Gas In Storage. The sole dispute is whether Working Gas in Storage should be included in the rate base for TXU Gas - Distribution or the rate base for TXU Gas - Pipeline.

The Examiners find that it is reasonable to include Working Gas in Storage in the rate base for TXU Gas - Pipeline. Although TXU maintained that Working Gas in Storage has been a Distribution asset since at least 1996, TXU did not include Working Gas in Storage as a component of rate base in rate proceedings affecting at least seven separate TXU regional distribution systems, with test years ending in 2000 and

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518 TXU Exhibit 61, Schedule B(D), page 1, line 12.
519 TXU Exhibit 38 at 6.
520 TXU Exhibit 27 at 7.
521 ACC Exhibit 3A at 14.
522 ACC Exhibit 3A at 14.
523 Dallas Exhibit 2 at 35.
524 Dallas Exhibit 2 at 35.
525 ATM Initial Brief at 26 (March 8, 2004).

2001.[526] The Examiners note that TXU witness Mr. Dane A. Watson sponsored TXU's schedules for total rate base in both this GUD 9400 proceeding and in the seven regional distribution rate cases.[527] In addition, during the hearing on the merits in this proceeding, Mr. Watson confirmed that Working Gas in Storage would have been listed on the rate base schedule for each of the regional distribution rate systems had it been a component of rate base.[528]

9. Investment Tax Credit (ITC) and Accumulated Deferred FIT (ADFIT)

Investment Tax Credit (ITC) accounts are cost-free capital on the books of a utility. ITCs are often used by utilities to reduce taxes. Usually, a deduction from invested capital is made to account for ITC. Accumulated Deferred Federal Income Tax (ADFIT) is the difference between total normalized FIT expense based on book net income and the amount of the current tax liability actually reflected on the FIT return. The deferred tax is subsequently amortized over the life of the asset or other basis that gives rise to the tax benefit or increase.[529]

TXU's Position
TXU reported the amount of unrestored investment tax credits (ITC) for Distribution was $10,340,440[530] and for Pipeline was $7,934,761.[531] TXU stated that no intervening party took issue with these amounts, and they should be included as credits (reductions) to invested capital.[532] TXU reported the amount of accumulated deferred federal income tax (ADFIT) for Distribution was $126,964,321[533] and for Pipeline was $62,909,895.[534] TXU stated that no intervening party took issue with these amounts, and they should be included as credits (reductions) to invested capital.[535]

Examiners' Recommendation
The evidence was uncontroverted. The Examiners recommend the proposed ITC and ADFIT adjustments be approved; therefore, Distribution invested capital should be reduced by $137,304,761 ($10, 340,440 + $126,964,321= $137,304,761) and Pipeline invested capital be reduced by $70,844,655 ($62,909,895 + $7,934,761).

10. Customer Deposits, Customer Advances for Construction, Injuries and Damages Reserve

TXU proposed to reduce its Distribution rate base by $24,590,346 for customer deposits; to reduce its Distribution rate base by $5,031,889 for customer advances for construction; and to reduce its Distribution

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[526] Hearing Examiners' Exhibit 1.
[527] Hearing Examiners' Exhibit No. 1
[528] Tr. Vol. 8 at 181 (Feb. 4, 2004).
[529] TXU Exhibit 19 at 3.
[530] Exhibit 61, Schedule E-7.2(D).
[531] Exhibit 61, Schedule E-7.2(P).
[532] TXU Exhibit 19 at 4; TXU Exhibit 61, Schedule E-7.2(D); TXU Exhibit 61, Schedule E-7.1(P).
[533] Exhibit 61, Schedule E-7.1(D).
[534] Exhibit 61, Schedule E-7.1(P).
[535] TXU Exhibit 19 at 4; TXU Initial Brief at 32.

rate base by $1,284,500 for injuries and damages reserve.[536] TXU proposed to reduce its Pipeline rate base by $272,500 for injuries and damages reserve.[537]

Intervening Parties' Positions
No intervening party opposed TXU's proposal.

Examiners' Recommendation
The Examiners recommend that TXU Gas - Distribution invested capital and TXU Gas - Pipeline invested capital be reduced by the amounts proposed by TXU for customer deposits, customer advances for construction, and injuries and damages reserve.

11. Asset Relocations

Issue Summary
TXU requested Commission approval of $55,660,675 as invested capital for the relocation of pipeline. Plant relocation costs for gas utilities are the costs of relocating gas facilities (e.g., mains, service lines, etc.) to accommodate construction or improvements. The construction or improvements generally relate to highway, road, street, public way, or other public works. As noted by TXU, many plant relocation projects occur in areas with high growth and increased economic activities. Municipalities may request pipe be relocated to allow for increased economic activities such as the examples of street or highway improvements. The majority of the pipe relocations considered in this proceeding were made in the Dallas/Forth Worth Metroplex area due to the high growth in that area.

The entity requesting the relocation of pipe should pay all or part of the costs of the requested relocation. Traditionally, the plant relocation costs shown to be reasonable and necessary were added to gas plant in service at the time the projects were shown to be used and useful. To the extent that these costs were not reimbursed by the cost-causing entity, the utility recovered them by including them in rates as invested capital, thereby increasing the utility's depreciation expense and return requirements for ratemaking purposes. TXU recorded reimbursements for plant relocation costs in Account 108, the accumulated provision for depreciation (i.e., in sub-account Other Recoveries). When a cost is considered to be invested capital, the cost is recovered through depreciation and the utility is given a reasonable opportunity to earn a reasonable return on its invested capital.

Effective in 1999, TUC §104.112, *Surcharge to Recover Relocation Costs*, was promulgated and provided a mechanism to utilities for an additional option to recover the un-reimbursed costs of relocation through the use of a surcharge. TUC §104.112 allows the surcharge to be recovered over a one to three year period, but there is no return or depreciation treatment.

TXU's Position
TXU stated that in calculating invested capital, it included plant relocation costs as part of the normal ratemaking recovery process. TXU argued that the costs were correctly recorded on its books, the assets were used and useful to gas customers, and the amounts are therefore properly included in invested

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[536] TXU Exhibit 14 at 7; TXU Exhibit 61, Schedules B(D), E-3(D), E-4(D), and E-5(D).
[537] TXU Exhibit 14 at 7; TXU Exhibit 61, Schedules B(P) and E-5(P).

capital.[538]

TXU made the following arguments. TXU is not required to recover plant relocation costs under TUC §104.112.[539] Instead, TUC §104.112 is another mechanism through which utilities can recover relocation costs. If the utility elects not to recover under TUC §104.112, it is not precluded from seeking reimbursement using the normal ratemaking recovery process, i.e., putting the costs into invested capital.[540] The capital investment assets relocated in accordance with a regulatory mandate or municipality's request are currently used and useful.[541] Therefore, this capital investment was reasonably incurred, because the relocations were mandated by city or other governmental entities and because the relocations were useful and beneficial to communities served by the utility.[542] The recovery of un-reimbursed costs of invested capital related to relocations is necessary to ensure the continued provision of gas utility service.[543] However, TXU is not required to conduct a study comparing the cost to ratepayers of including relocations in invested capital versus the cost of surcharging relocation costs under TUC §104.112.

In response to ATM's arguments, TXU stated that a municipality cannot, through its franchise agreements, preclude a utility from recovering costs reasonably incurred for the provision of gas utility service in defiance of the governing statutes.[544] TUC §104.053 requires that the Commission and municipalities allow TXU to recover costs used and useful in providing service to the utility customers and that all of the capital investment that was relocated pursuant to a regulatory mandate, whether the utility was reimbursed or not, is used and useful and reasonably incurred.[545] Thus, a municipality is without the authority to take any action contrary to state law, such as §104.112, because municipalities have no inherent authority to regulate utilities. In other words, TXU argued that municipalities have only the specific authority granted to them by the legislature.[546]

The Commission allowed TXU to include relocation costs in proceedings subsequent to the enactment of TUC §104.112. TXU urged that the Commission should not disallow these costs solely based upon ATM's desire that the utility use TUC §104.112 to recover costs through a surcharge. Recovery of the investment for relocations should be allowed.[547]

TXU argued that ATM's position-- that relocations are used and useful to some communities while not necessarily used and beneficial to other communities served by the utility-- is misplaced. TXU argued that legal precedent supported the utility's decision to recover relocation costs in invested capital, and gave as an example the Public Utility Commission of Texas' (PUC) unbundled cost of service (UCOS) proceedings regarding electric restructuring in which the issue of municipal franchise fee allocation was examined. The PUC held that such fees (referred to as Local Gross Receipts Taxes or LGRT) should be

[538] TXU Exhibit 27 at 7; TXU Exhibit 13 at 6.
[539] TXU Exhibit 27 at 6-7; Exhibit 27, attachment DAW-R-1.
[540] TXU Exhibit 27 at 6-7; Exhibit 27, attachment DAW-R-1.
[541] TXU Exhibit 26 at 19.
[542] TXU Exhibit 26 at 19.
[543] TXU Exhibit 26 at 19; TXU Exhibit 27 at 6-7; TXU Initial Brief at 15.
[544] TXU Reply Brief at 11.
[545] TXU Exhibit 26 at 19.
[546] *Southwestern Bell Telephone Co. v. Houston Independent School Dist.*, 397 S.W.2d 419 (Tex. 1965).
[547] TXU Exhibit 27 at 6-7.

collected from all customers on a transmission and distribution company's system, rather than collecting them solely from those customers located within the municipal boundaries.[548] TXU reported that the PUC determined the collection of LGRT from all customers on a utility's system serves the entirety of the transmission and distribution system, benefits all customers in the system and, consequently, the costs should be shared among all customers through base rates. TXU noted that the PUC also found that collecting revenues from all customers honors the principle of equity for customers within rate classes.[549] TXU argued that, like LGRT, the inclusion of relocation costs in invested capital is consistent with this recent regulatory policy and precedent in Texas and will result in equitable rate treatment across the utility's customer classes.[550]

ATM

ATM based its arguments on the ratemaking principle that the customer or entity for whom service is provided should pay the costs necessary to provide service. ATM reported that from 1998 to 2002, TXU was reimbursed $12,600,240 of the $100,924,625 costs for plant relocation. ATM provided a summary of the TXU's 1998 to 2002 plant relocation costs by year.[551]

The relocation projects were for street or highway improvements and were performed by TXU at the request of a municipality and were to allow for increased economic activities. Because most of the relocation projects were in the high growth area of the Metroplex, those municipalities that required TXU to relocate its gas pipe should bear the cost incurred for plant relocation. The rest of the communities should have no responsibility for the relocation costs incurred.[552]

ATM argued that TXU failed to show how communities located far from a plant relocation project are benefitted. ATM Exhibit 33 listed relocation projects costing more than $2,000,000, which were undertaken between 1988 and 2002. ATM noted that over 90 percent of these projects took place in the Metroplex, i.e., the Dallas/Fort Worth metropolitan area. TXU provided no evidence showing that ratepayers in the Hill Country, Bryan/College Station, Longview, or Bandera would benefit from any of these projects.[553] ATM argued that TXU provided no evidence and undertook no study to compare the cost of utilizing the recovery mechanism provided by TUC §104.112 (surcharging) versus putting the expense into invested capital. For the relocations required by the City of Dallas, that city (and its residents) received the benefit of the increased economic activity that caused the need for the pipe relocation. While these relocations are useful or beneficial within the Metroplex, this does not mean that such projects are useful or beneficial in Austin, Somerville, or Fredericksburg or in any of 200 other communities far away from the Metroplex. ATM argued that if these relocation costs are put in invested capital, the low-growth or no-growth communities will subsidize the high growth communities which received the benefit of high

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[548] TXUReply Brief at 10-11 (Mar. 17, 2004); *Application of TXU Electric Company for Approval of Unbundled Cost of Service Rate Pursuant to PURA §39.201 and Public Utility Commission Substantive Rule §25.344,* PUC Docket No. 22350, Order at 163-64, 190 (Oct. 3, 2001); *Application of Reliant Energy for Approval of Unbundled Cost of Service Rate Pursuant to PURA §39.201 and Public Utility Commission Substantive Rule §25.344,* PUC Docket No. 22355, Order at 135, 149, 163 (Oct. 4, 2001).

[549] PUC Docket No. 22350, Order at 163-64; PUC Docket No. 22355, Order at 149.

[550] TXU Reply Brief at 10-11.

[551] ATM Exhibit 1, attachment MLA-4, line 6, columns (C) and (E).

[552] ATM Exhibit 1 at 27; TXU Exhibit 26 at 19.

[553] Tr. Vol. 2 at 117-118.

economic development and the benefit of the relocations. Since September 1, 1999, TXU could have used TUC §104.112 to surcharge those communities which are benefitting from the increased economic development.[554]

ATM took the position that TXU failed to meet its burden to show that the rates are just and reasonable because the utility must not only show that invested capital is used and useful but also that the costs which constitute the invested capital are reasonable and necessary. ATM argued that TXU failed to prove the cost incurred by TXU for relocation projects was reasonable or necessary.[555]

ATM argued that TXU should have provided evidence showing the treatment of relocation costs as invested capital produces more favorable results to the ratepayer than when projects are surcharged to the municipalities that caused the relocation expense to be incurred. TXU provided no such evidence. Instead, TXU explained that the relocation projects were not surcharged due to concern that the surcharge could have been unduly large in small communities.[556] ATM noted that TXU provided no basis for its position that a small city would wind up with a large surcharge. ATM argued that the need for a relocation is due to economic growth and that the record does not show that small cities are experiencing significant growth or that relocations were needed in small towns. ATM argued that TXU did not put forth a single concrete example where a relocation in a smaller populated community would result in a significant surcharge.[557]

ATM recalled that the Commission previously addressed a similar issue. Southern Union Gas Company (now Texas Gas Service) had two surcharge cases before the Commission. ATM reported that in GUD 9174, there were 23 relocation projects involved. Twenty-two of the projects were located in Austin and one project was located within the City of Sunset Valley at a project cost of $120,337. The City of Sunset Valley has a population of 427. Southern Union demonstrated to the Commission that the Central Texas cities of Austin, Westlake, Sunset Valley, Rollingwood and Cedar Park benefitted from the relocation projects due to the proximity and common use of roadways. Thus, all the cities that were surcharged for the 23 projects, including the Sunset Valley project, were shown to be those municipalities in proximity to the relocation projects and to be the municipalities with ratepayers who would benefit from the relocation projects. In GUD 9174, the Commission also found that Southern Union had sought reimbursement from the central Texas municipalities before requesting the Commission approve a surcharge.[558]

ATM argued that there was no effort by TXU to show that the utility had sought reimbursement from the governmental entity or the regulatory entity that ordered the Distribution pipe to be relocated for each relocation project. ATM stated that even if TXU could not be reimbursed by the governmental entity that ordered the relocation, the utility made no effort to show that it sought to surcharge the customers in the area, as did Southern Union Gas. ATM emphasized that TXU provided no evidence that it had attempted to be reimbursed from the cost-causing entity before requesting the Commission approve inclusion of these relocation costs in invested capital.

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[554] ATM Exhibit 1 at 27; ATM Initial Brief at 44-45 (Mar. 8, 2004); ATM Reply Brief at 23-26 (Mar. 17, 2004); Tr. Vol. 1 at 109-117; Tr. Vol. 2 at 117-118.

[555] ATM Initial Brief at 44-45 (Mar. 8, 2004); ATM Reply Brief at 26 (Mar. 17, 2004).

[556] Tr. Vol. 1 at 1112.

[557] ATM Initial Brief at 43-44 (Mar. 8, 2004); ATM Reply Brief at 23-26 (Mar. 17, 2004).

[558] ATM Reply Brief at 25 (Mar. 17, 2004).

ATM also argued that TXU had failed to show the reasonableness and necessity of the relocation projects or the relocation costs. The relocations ordered by a governmental entity were not a "necessary" cost for the general body of TXU ratepayers. There is no benefit to the general body of ratepayers for a relocation that was ordered by the City of Allen or by any other Metroplex city. A relocation ordered by the City of Round Rock is also not of benefit to the Metroplex ratepayers or to the general body of ratepayers. Thus, such relocations are not "necessary" except to the area where such relocations occur.[559]

ATM acknowledged TXU's argument that TUC §104.112 is permissive and therefore the utility does not need to show that it attempted to surcharge the relocation costs to customers of the cities who ordered the relocations. ATM responded that TXU's argument is misplaced. TXU has the burden to show that the relocation costs are "necessary" costs for the general body of ratepayers to bear. ATM argued that TXU failed to provide evidence that its tracking of property accounts is a problem. ATM noted that today, rate case expense surcharges, franchise fee collections, and local tax collections are done on a city-by-city basis, but TXU offered no evidence why keeping property accounts on a city-by-city basis would be a problem. TXU has never previously complained to the Commission about being able to properly perform these tasks. ATM argued that other gas utility companies are able to track property accounts on a city-by-city or on a small distribution system-by-small distribution system basis. Therefore, ATM concluded that this is an excuse and has no merit.[560]

TXU indicated that getting municipal approval for the surcharge is a problem. Yet, ATM noted, TXU provided no basis for this statement because TXU never tried to surcharge relocation costs using TUC §104.112. ATM argued that TXU did not provide any evidence that the utility ever sought reimbursement, or even partial reimbursement, from the municipalities which ordered the relocations. ATM argued that the relocation costs were not necessary and TXU made no attempt to show it had requested reimbursement from any of the cities that ordered the Distribution or Pipeline mains to be relocated. ATM identified this omission as TXU's fatal flaw. Pipes are relocated because cities and other governmental entities order the pipes to be relocated. The city that orders the pipes to be relocated is getting the benefit of increased economic activity.[561]

As a result of the municipality's action, TXU has a claim to be reimbursed by the municipality, as a governmental entity, causing TXU to incur the expense. For any relocation expense that was not recovered, TXU could seek approval of a surcharge from the municipality as the regulatory authority. TXU offered no evidence of what action, if any, it took to be reimbursed from the local governmental entity as the cost-causing entity. TXU offered no evidence of what action, if any, it took to seek approval of a municipal surcharge for reimbursement of unrecovered amounts. ATM provided the hypothetical that if a city vehicle damages a TXU pickup truck, TXU would first make a claim against the municipality before it could ask ratepayers to pay for fixing its pickup truck. Before a cost can be shown to be "necessary," TXU must exhaust its third-party claim possibilities. ATM claimed that this was common sense. Before TXU is allowed to surcharge relocation costs under TUC §104.112 it is required to show "that reasonable efforts have been made to receive reimbursement from the entity requiring the relocation." ATM argued that the statute codified the evidence that TXU is required to produce to show that the relocation cost is

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[559] TXU Reply Brief at 23, 26-30 (Mar. 17, 2004).

[560] ATM Reply Brief at 25(Mar. 17, 2004); Tr. Vol. 1 at 113.

[561] ATM Reply Brief at 26 (Mar. 17, 2004); Tr. Vol.1 at 123-124.

a "necessary" cost to be borne by the general body of ratepayers. ATM concluded that TXU should have produced this same evidence at the hearing if TXU wanted to show that the general body of ratepayers should be charged for relocation costs by adding them to TXU's invested capital.[562]

TXU did not file testimony showing that it sought reimbursement from the governmental entities that ordered the pipes to be relocated. Thus, TXU did not show that it is "necessary" for the general body of ratepayers to be obligated to pick up the tab for the relocation costs. In light of TXU's failure to show it sought reimbursement from the cost-causing municipalities or governing entities, TXU has not proven that the total cost for plant relocations is reasonable. TXU provided no board minutes, reports, memoranda, analyses, or calculations to support the utility's decision to include relocation costs in invested capital rather than attempting to create a surcharge in those cities for which relocations were performed.[563]

ATM and TXU were in agreement that TXU's right to seek reimbursement of relocation costs from ratepayers is not controlled by franchise agreements. TXU argued that municipal franchise agreements do not impose an impediment to the third-party recovery against cities that order distribution pipes to be relocated. ATM argued that to the extent that the franchise agreement requires TXU to assume relocation costs without reimbursement from the municipality, TXU is also not entitled to seek reimbursement in this proceeding before the Commission. TXU offered no evidence of its right to seek compensation or reimbursement for relocation costs under the municipal franchise agreements. Therefore, TXU's request should be disallowed.[564]

ATM argued that because TXU failed to meet its burden to show that the plant relocations were useful to the general body of ratepayers and that the total cost for relocations is reasonable, the Commission should disallow from invested capital $55,660,675. On an annual basis this means that return of $6,673,715 is disallowed along with the associated depreciation of $1,942,558. TXU is free to seek reimbursement from the city or governmental entity that ordered the pipe to be relocated and then to seek a surcharge under TUC §104.112 to recover the relocation costs that were not reimbursed.[565]

ATM referred to the activities of the PUC to support its argument that TXU must show that it attempted to recover expenses from third parties, when applicable, before seeking to add a cost to invested capital. ATM reported that the PUC was confronted with the issue of whether ratepayers should be charged for "Batch 10" nuclear fuel costs. The Batch 10 nuclear fuel had properties which made the fuel useless for producing electricity. The Batch 10 issue came up in the context of a fuel reconciliation proceeding. The administrative law judge decided that the Batch 10 costs should not be borne by ratepayers until the utility, Entergy Gulf States, had shown that it had pursued recovery from third-party sources. In other words, the Batch 10 costs were not "necessary" until the utility had shown it could not recover those costs from third parties. The PUC made the following finding: "It is appropriate to defer reconciliation or review of the failed Batch 10 fuel costs, in the amount of $4,721,492, until such time as potential insurance or warranty claims have been resolved."[566]

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[562] ATM Reply Brief at 26-27(Mar. 17, 2004); ATM Exhibit 1 at 27.

[563] ATM Reply Brief at 26-27 (Mar. 17, 2004).

[564] ATM Exhibit 1 at 29; ATM Initial Brief at 46 (Mar. 8, 2004); ATM Reply Brief at 28 (Mar. 17, 2004); TXU Reply Brief at 11.

[565] ATM Initial Brief at 45-47; ATM Exhibit 1, attachment MLA-4.

[566] ATM Reply Brief at 28 (Mar. 17, 2004).

TXU failed to refute the intervening party's position that it is unfair for the general body of ratepayers to subsidize cities that require pipeline relocations. ATM testified that gross subsidies occur when the general body of ratepayers pay for costs relating to city-ordered relocations. ATM argued that customers in low growth areas should not be required to pay for expensive relocations which provide economic benefits to other areas. TXU's March 8, 2004, Initial Post Hearing Brief did not dispute ATM's position on this subject. Because TXU did not provide clear and convincing evidence that it took reasonable steps to secure reimbursement or to surcharge area customers, the utility should not be allowed to pass these costs on to the general body of ratepayers.[567]

From 1998 to 2002, TXU Gas Distribution spent approximately $101 million on plant relocation costs. TXU intends to spend similar amounts in the future for plant relocations. TXU's 2003 - 2007 Capital Expenditure Plan projected that the utility will spend approximately $102 million on plant relocation costs in the next five years. The estimates include $22.1 million in 2003 and $20.0 million per year from 2004 to 2007.[568]

Under TUC §104.112, a gas utility must file an application to recover plant relocation costs with the regulatory authority where the relocation occurred. The application must demonstrate: (1) the requirement for each relocation; (2) the entity requiring the relocation; (3) costs incurred for relocation of comparable facilities; (4) surcharge computation; and (5) that reasonable efforts have been made to receive reimbursement from the entity requiring the relocation. The gas utility's application must be granted or denied within 30 days. Reasons for denying the application include a finding that: (1) the relocation was not necessary or required; (2) the costs of the relocation were excessive or not supported; (3) the utility did not pursue reimbursement from the entity requiring the relocation; (4) the surcharge is unduly discriminatory among customers or classes of customers located in the service area; or (5) the period over which the relocations costs are designed to be recovered does not comply with the one to three year period allowed by TUC §104.112.[569]

ATM argued that the benefit of TUC §104.112 is that the gas utility may recover plant relocation costs from the customers who benefit from that plant relocation. Many of the relocations are in areas of high growth and the relocations provide for increased economic activities. Customers in low growth areas should not be required to pay for expensive relocations which provide economic benefits to other areas. The Act results in more equitable recovery of plant relocation costs.

Because the surcharge is a visible cost to customers, ATM argued that gas utilities and the entities that cause the plant relocation costs should be more inclined to cooperate in order to fully plan facility relocations. ATM reasoned that this should result in lower costs and greater efficiencies.[570]

ATM stated that TUC §104.112 results in greater review of the relocation projects on an individual project basis. ATM noted that in utility rate cases, there are usually so many issues that review of individual

[567] ATM Reply Brief at 29-30 (Mar. 17, 2004).
[568] ATM Exhibit 1 at 27-28.
[569] ATM Exhibit 1at 29-30.
[570] ATM reply Brief at 29 (Mar. 17, 2004).

projects may not be possible. However, review of the individual projects on a local level should improve regulatory oversight and may result in lower costs.

ATM noted that in the four years TUC §104.112 has been in effect, TXU has never used the surcharge provisions and provided no evidence in this proceeding why. TXU stated that its policy for facility relocation costs which are not reimbursed by another party is to add the costs to plant in service at the time the projects go into service. Those amounts are recovered through normal rate-making treatment by inclusion as invested capital. TXU further stated that TUC §104.112 would allow the utility, at its discretion, to surcharge those amounts in rates. But, after consideration, the utility decided to continue including those amounts as normal invested capital additions in regulatory proceedings.[571]

ATM concluded that because the utility failed to utilize the provisions contained in TUC §104.112, increased un-reimbursed plant relocation costs, increased invested capital, increased return, and increased depreciation requirements resulted. TXU provided no documentation or analyses to support its decision not to use TUC §104.112. TXU's failure to use TUC §104.112 increased costs and caused harm to ratepayers who have been subsidizing plant relocation costs of others. TXU did not demonstrate that it is appropriate to spread these costs systemwide as opposed to utilizing the mechanisms of TUC §104.112. Therefore, ATM recommended that the Commission not allow relocation costs to be recovered on a systemwide basis, but rather only through the application of TUC §104.112.[572]

Examiners' Recommendation

In this proceeding, the Examiners considered whether TXU's request for approval of unrecovered relocation costs was proper and whether the costs were reasonable and necessary. The Examiners' analysis of the cost of relocation was made in two parts. First, the Examiners considered whether TXU was required to use TUC §104.112. The Examiners find that TUC §104.112 is not a mandatory provision. Utilities may use TUC §104.112 to seek interim recovery of invested capital through a surcharge, but are not required to do so.

Finding that TUC §104.112 is not mandatory, the Examiners next considered whether TXU had provided evidence to meet its burden to show that these costs are reasonable and necessary to gas utility customers for the provision of gas utility service. The Examiners find that TXU failed to provide meaningful, probative evidence to support its request for relocation reimbursement as invested capital. Therefore, the Examiners recommend that the Commission disallow from invested capital $55,660,675. On an annual basis this means that return of $6,673,715 is disallowed and the associated depreciation of $1,942,558 is disallowed.

The Examiners acknowledge that there may be rate proceedings, past and future, in which the Commission appropriately finds that relocation costs that were not reimbursed by the cost-causing entity are reasonable and necessary and therefore allow the utility to include the expense as invested capital. However, this is not such a proceeding. TXU failed to provide probative evidence to support its proposed request and to allow the Commission to make a finding of reasonableness or necessity of the cost.

[571] ATM Exhibit 1 at 31.
[572] ATM Exhibit 1 at 33.

TXU stated that it was not required to seek relief through a surcharge under TUC §104.112, and had instead appropriately recorded the un-reimbursed expenses on its books for inclusion as invested capital. However, by simply opening its books to inspection, a utility enjoys no presumption that the expenditures reflected therein have been prudently incurred.[573] The utility is required to put forth evidence to support its proposed inclusion of the cost in invested capital. The Examiners find that TXU did not provide evidence showing why the relocations were necessary or how the relocations were applicable to gas utility services. The evidence did establish that the relocations were required by a municipality or other regulatory entity. However, stating that a municipality or other governmental entity required relocation of an asset is neither material nor probative evidence that the costs were necessary for the provision of gas utility service. TXU did not show that the relocations were reasonable and necessary for a utility need. The Examiners find that the relocations may have been necessary for repair or building of street or highway, but were not shown to have been necessary for the provision of gas utility service to gas customers. TXU did not provide evidence that the expense it incurred for relocation was reasonable. Whether the utility undertook the relocation project at the request of a municipality or other governing entity is not probative or material evidence that the asset relocation costs were reasonable and necessary for the procurement of gas utility service.

TXU provided no evidence showing mitigation of the costs it now seeks to recover from rate payers so that the requested inclusion of un-reimbursed expenses could be considered reasonable. TXU provided no evidence that it took reasonable measures to seek reimbursement from the municipality or other governmental entity that had requested TXU to undertake the relocation project. TXU provided no evidence that it sought reimbursement for relocation projects from the cost-causing entities or that the cost-causing entity had refused to reimburse TXU for those relocation costs. ATM requested TXU to explain the reasons why relocation projects were not fully reimbursable.[574] In response, TXU made an assertion that projects involving municipalities are not reimbursable – but provided no reference or documentation to support this position.[575] TXU cannot prove its expense request is reasonable if it provides no evidence that it attempted to mitigate the costs to its customers or if it provides no evidence to support its position. The Examiners do not find that the costs were reasonable.

TXU stated that the impact of asset relocation to customers in a small town could be tremendous.[576] This statement is not probative evidence. The record evidence shows that relocations tend to occur in areas with high growth and increased economic activity. TXU provided no probative evidence that relocation projects were prevalent outside of such high-growth areas. TXU presented no evidence showing that there is decreased impact to customers in a small town through use of TXU's proposed invested capital treatment rather than through a surcharge to the customers in the area where the relocation occurred. The Examiners found no evidence to show that customers located in municipalities other than the high growth areas where the relocation projects occurred should bear the costs of relocation projects for which TXU was not fully reimbursed by the entity causing the cost. The Examiners found no material or probative evidence showing that customers who are not located near the relocations would receive any benefit from the relocations. Therefore, it is reasonable for the Commission to deny TXU's request for asset relocation costs.

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[573] *Coalition of Cities for Affordable Utility Rates v. Public Utility Commission of Texas*, 798 S.W.2d 560, 563 (Sept. 12, 1990) Rehearing Overruled (Nov. 28, 1990).

[574] ATM Exhibit 33.

[575] ATM Exhibit 33.

[576] Tr. Vol. 1 at 112.

The Examiners did not find TXU's example of the PUC's treatment of local gross receipts taxes (LGRT) in its electric restructuring unbundling-cost-of-service (UCOS) cases to be probative. In this proceeding, TXU failed to provide evidence showing that asset relocations are of benefit to the entire system to justify that costs could be shared among all customers.[577]

TXU stated that keeping separate property records and appropriate calculation of return to assure that there is no double recovery could be a problem.[578] TXU also stated that getting approval of the surcharge mechanism was a problem. However, provided no meaningful, probative evidence to support these conclusions. TXU provided no evidence showing how or why record keeping or getting approval of the mechanism was a problem and provided no evidence countering evidence that TXU currently accounts for rate case expense surcharges, franchise fee collections, and local tax collections on a city-by-city basis.[579] TXU did not provide evidence showing that a surcharge for relocation costs applied on a city-by-city basis would adversely impact TXU's pursuit of system-wide rates.[580]

The Examiners do not find that TXU was required to perform a study comparing costs to ratepayers of including relocations in invested capital versus surcharging relocation costs under TUC §104.112. TXU, is however, required to present evidence showing the necessity and reasonableness of its proposal to include relocation costs as invested capital. TXU is not bound to any single method for presenting such evidence. However, the Examiners find that TXU did not offer any such evidence. TXU did not show that the relocation costs were a benefit to the entire system. The record evidence did not demonstrate that it is reasonable to spread the costs system-wide, as opposed to having those customers who benefit from the relocation pay those costs.

The record does not show that municipalities used their franchise agreements to preclude TXU from recovering costs from the municipalities that required relocations. Such provision would be contrary to the requirements of TUC §104.053 that utilities be allowed to recover costs shown to be used and useful in providing service to the utility customers.

TXU concluded that the relocated pipe is used and useful, but failed to provide meaningful, probative evidence showing the relocation costs were reasonable and necessary. Having considered all the evidence relating to pipeline relocation costs, the Examiners find that TXU failed to show its request for inclusion of un-reimbursed plant relocation costs in invested capital, thereby recovering from all system-wide ratepayers is reasonable and necessary.

- TXU failed to show that the amount requested is reasonable.
- TXU failed to show that the costs it incurred were reasonable.
- TXU failed to show that the costs were reasonable and necessary for the provision of gas utility service rather than for an economic activity, such as for construction or for improvements in a high-growth area.
- TXU failed to show that before seeking Commission approval to include asset relocation costs in system-wide rates, the utility had mitigated costs by seeking reimbursement from

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[577] TXU Reply Brief at 11.
[578] Tr. Vol. 1 at 113.
[579] Tr. Vol. 1 at 123-124
[580] Tr. Vol. 1 at 121.

the cost-causing entity, so that the costs to TXU Gas customers would be reasonable.

- And, TXU failed to show that before seeking Commission approval to include asset relocation costs in system-wide rates, the utility had mitigated costs by seeking approval of a surcharge applicable to the cost-causing municipality, so that the costs to TXU Gas customers would be reasonable.

12. Transfer of Facilities

<u>*Issue Summary*</u>
The function or use of plant assets may change between Pipeline and Distribution. Plant assets are classified according to their operational function. TXU has previously transferred and reclassified assets to reflect the function currently served by the assets as compared to the function being served when those assets were originally installed.[581] The issue of the transfer of facilities impacts rate base, depreciation expense, and costs of labor.

<u>*TXU's Position*</u>
TXU explained that if an asset functions primarily as a distribution asset when it is installed, it is classified as a TXU Gas - Distribution asset; if an asset functions as a transmission asset when it is installed, it is classified as a TXU Gas - Pipeline asset. Changes in environment occur in the vicinity of a pipe segment; therefore, the utility analyzes those pipe segments and may re-classify the pipe according to its use. Weighted criteria used by TXU to functionalize the specific assets include the following concepts. Storage assets belong to Pipeline. Distribution assets provide primarily a firm (human needs) purpose rather than providing a primarily interruptible service. Functionalization of assets produces contiguous systems. Systems that are net exporters of gas to a transmission asset should remain as transmission assets. The number of taps or customers on a given pipe should be considered. Distribution assets should be downstream of treating, whenever practical.[582]

TXU gave the following as an example. If in year 1, Pipeline installed a transmission pipeline in an open field in an unpopulated area then the asset would be a Pipeline asset. If in year 5, the area around the same pipeline had become densely populated and began serving more as a Distribution asset than a transmission asset, then the pipeline would likely be re-classified to Distribution, according to its new function. This type of activity and analysis is part of TXU's on-going effort to properly serve its customers and charge rates accordingly.[583]

TXU stated that the facility transfers are consistent with their current operational uses; the transfers were properly recorded on the utility's books and records consistent with NARUC accounting principles; and assets should be aligned with their proper operating function. TXU argued that ACC's proposal to reverse all transfers between Pipeline and Distribution since July 1, 1999, would reduce rate base by adjusting depreciation expense but would be consistent with their functions. TXU further noted that ACC's proposal contained errors in the proposed adjustment calculations. First, ACC did not use the correct Pipeline

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[581] TXU Exhibit 26 at 16-18; Tr. Vol. 7 at 69-81.
[582] TXU Exhibit 26, attachment JAG-R-8; TXU Initial Brief at 57-58 (Mar. 17, 2004).
[583] TXU Exhibit 26 at 17-18.

depreciation rate to calculate accumulated depreciation expense for Pipeline. Second, ACC did not account for the actual timing of the transfers to calculate the adjusted accumulated depreciation balances.[584] TXU calculated the impact of reversing the transfers, as recommended by ACC, but corrected ACC's calculation errors.[585] TXU argued that it did not manipulate depreciation rates; rather, the utility made operational and management decisions to transfer the assets to be consistent with their current use, as compared to their use at the time of installation.[586]

In response to ACC's statement that reclassification should be prohibited to prevent the possibility of double recovery, TXU argued that all of the investment in both Distribution and Pipeline is before the Commission in this case; therefore, double recovery is not possible.[587] TXU responded that rates are established based on a snapshot in time of the utility's rate base, but that its expenses and revenues are not static. Assets are bought, sold, conveyed, and transferred all the time. The transferred assets have not ever been simultaneously included in both the Pipeline and Distribution rate bases. Rather, pursuant to NARUC Plant Instruction 12, the utility transferred, at net book value, the functionalized assets to the appropriate division of TXU Gas based on relevant operating considerations, and simultaneously removed the transferred asset from the rate base of the other division of TXU Gas.[588] TXU argued that ACC's proposal would result in customers of one division continuing to pay for an asset that is no longer used and useful to them. This result is inconsistent with NARUC accounting principles, Commission statements, and cost of service ratemaking principles and should therefore be rejected. TXU also argued that ACC's proposal is retroactive ratemaking.[589]

TXU stated that there is no accounting principle that precludes the transfer of assets. The utility's treatment of the transferred assets comports with NARUC Utility Plant Instruction No. 12, which requires TXU to properly assign its functionalized assets to each division of TXU Gas at net book value based on the transfer decisions made by Distribution and Pipeline operations personnel.[590]

TXU stated that ACC's cross examination of TXU's witness Greer did not show that the utility does not know where reclassified lines are located, when they were installed, or why they were reclassified. TXU argued that just because Mr. Greer could not recognize the location of certain assets by a numbered line location does not mean that TXU does not have employees with that information or that TXU classified assets in a haphazard manner. TXU described the reasonableness of the process by which it evaluates its assets.[591]

ACC

ACC recommended several adjustments to TXU's proposed rate base. One of these adjustments related to TXU's transfer of vintage plant. ACC proposed to reverse all transfers between Pipeline and Distribution since July 1, 1999, thereby reducing rate base by adjusting depreciation expense. This resulted

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584 TXU Initial Brief at 12-13 (Mar. 8, 2004).
585 Hearing Examiners' Exhibit 3.
586 TXU Exhibit 26 at 17-18; Tr. Vol. 7 at 69-81.
587 TXU Reply Brief at 7 (Mar. 17, 2004).
588 TXU Reply Brief at 7-8 (Mar. 17, 2004); TXU Exhibit 37 at 5.
589 TXU Reply Brief at 7-8 (Mar. 17, 2004).
590 TXU Exhibit 27 at 5 -6.
591 Tr. Vol. 7 at 75-77.

in a reduction of Distribution plant in service of $8,324,223.[592] ACC argued that reclassification should be prohibited to prevent possible double recovery if the asset was included in the calculation of rate base for both Distribution and Pipeline.[593]

ACC noted that TXU's last Pipeline rate case was GUD 8976 (1999). In that docket, TXU's Pipeline rate base was established and Pipeline depreciation rates were set for the assets included in the Pipeline rate base, at that time. The city gate rate included a return on these assets as well as recovery of the depreciation expense. Since the issuance of the Final Order in GUD 8976, TXU filed a number of Distribution rate cases, including seven regional cases. ACC stated that since the issuance of the Final Order in GUD 8976, TXU has reclassified assets from Distribution to Pipeline, and vice versa. As assets were reclassified from Pipeline to Distribution, the assets were included in Distribution plant in TXU's Distribution rate cases; yet, the city gate rate that is also charged to Distribution customers has never been adjusted to reflect the transfers. In GUD 9400, TXU proposed to remove the assets from Pipeline rate base and the associated rate treatment. Until December 31, 2002, the assets that had been reclassified as Distribution assets from Pipeline were included in the calculation of both rate bases. Until December 31, 2002, the assets that had been included in the calculation of both rate bases were also included in both returns received by the utility; until December 31, 2002, the assets that had been included in the calculation of both rate bases and in both returns received by TXU were also being depreciated at two different depreciation rates (1.61 percent for Pipeline plant and 2.7 percent for Distribution plant).[594]

ACC did not agree with TXU that its reclassifications were necessary or appropriate. ACC stated that there is nothing that requires TXU Gas to periodically re-evaluate the operational use of its assets.[595] ACC argued that if the Commission allows the transfers of plant, then the Commission should reverse the double-recovery of both Pipeline and Distribution return and of the depreciation expense of the assets that were included in the city gate and Distribution rate charged to customers. ACC's calculation of the effect of the complete reversal of the reclassifications determined that Distribution plant in service would be reduced by $8,324,223.[596] In its March 8, 2004, Initial Brief at 15, footnote 38, ACC stated that the corrected impact of the transfers is $8,538,117.68.[597]

ACC claimed to have properly calculated the amount of assets transferred and the appropriate restatement of a reversal of the depreciation expenses associated with the transfers. The original cost of the assets transferred from Pipeline to Distribution was approximately $19 million. The original cost of the assets transferred from Distribution to Pipeline was approximately $3.4 million. If the assets had not been transferred, the Distribution assets (currently classified as Pipeline) would have been depreciated using the Distribution depreciation rate and the Pipeline assets (currently classified as Distribution) would have been depreciated using the Pipeline depreciation rate. ACC used the depreciation rate of 2.70 percent to restate Distribution depreciation on the assets that ACC recommends be transferred back from Pipeline to Distribution. ACC argued that despite the fact that communities continued to have a depreciation rate of

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[592] ACC Initial Brief at 14 (Mar. 8, 2004).
[593] ACC Initial Brief at 14-15 (Mar. 8, 2004).
[594] ACC Exhibit 3, attachment CTC-13; ACC Exhibit 101, attachment EB-4(D); ACC Initial Brief at 14-15 (Mar. 8, 2004); Hearing Examiners' Exhibit 3; Tr. Vol. 8 at 170.
[595] ACC Exhibit 3 at 6.
[596] ACC Initial Brief at 15 (Mar. 8, 2004).
[597] Hearing Examiners' Exhibit 3.

2.70 percent in 2002 and until August 2003, TXU maintained that the cities it served had a composite depreciation rate of 3.12 percent as of 2002. ACC stated that TXU agreed with ACC that if the assets were transferred back to their original classifications at the time of GUD 8976, the accumulated depreciation would have to be restated.[598]

ACC argued that it was inappropriate for TXU to have reclassified assets that were not required to be transferred by the utility's functionalization criteria. ACC stated that TXU did not provide a cogent reason for transferring the assets from Pipeline to Distribution or from Distribution to Pipeline. ACC criticized TXU's functionalization criteria because the criteria contain no specific requirements. ACC argued that the use of the asset does not change with its reclassification. ACC also asserted that TXU does not know specifically where the reclassified lines are located, when the lines were installed, or the reason for transferring each asset.[599]

ACC stated that assets that TXU transferred from Pipeline to Distribution have continued to be included in the Pipeline city gate rate, even though TXU classified the assets as Distribution assets in the seven regional cases. The transferred plant has varying vintage years; if the assets were in service prior to GUD 8976, then they would have been included in the Pipeline rate base. The assets that were subsequently transferred to Distribution were included in the Pipeline rate base in GUD 8976, and therefore generated a return and recovery of depreciation expense for TXU. No adjustments were filed to the Pipeline city-gate rate since GUD 8976 to reflect these transfers out of Pipeline. ACC argued that TXU admitted that if the books of particular cities had the transferred assets, then they would have been reflected in the Distribution schedules from the regional cases. ACC concluded that there is a double recovery of the return on and depreciation of these assets included in the GUD 8976 Pipeline case and again in a regional Distribution case.[600]

ACC argued that as a result of the transfers proposed by TXU, assets are included in functional groups with different useful lives, different depreciation requirements, and different net salvage value, even though the assets have not changed, nor have their useful lives. ACC stated that TXU confirmed that the transferred assets would now be included in the depreciation studies based on their new classification, even though the actual life and replacement of the individual assets have not changed.[601]

ACC stated that TXU was not forthcoming with requested data showing the revenues and volumes associated with the transfer of the utility's customers from Pipeline to Distribution, as a result of the reclassification. TXU provided three different responses, initially stating that the requested information was not available, then providing two different sets of data. ACC stated that the inaccurate and late data had conflicting usage and revenue information; had conflicting customer notations; and conflicted with TXU's original position that such data were not available. ACC challenged the knowledge of TXU witness Greer because he could not state whether O&M expenses had been quantified for the transfer of the assets. Mr. Greer sponsored TXU's response to ACC's request for information relating to the number of customers related to the plant transfers from Distribution to Pipeline. Because Mr. Greer responded that

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[598] ACC Initial Brief at 15-16 (Mar. 8, 2004); Tr. Vol. 8 at 152 - 160.

[599] TXU Exhibit 26, attachment JAG R-8; Tr. Vol. 7 at 72-81; ACC Initial Brief at 16-17 (Mar. 8, 2004).

[600] ACC Initial Brief at 17 (Mar. 8, 2004); Tr. Vol. 7 at 77 - 79; Tr. Vol. 8 at 169 - 176.

[601] ACC Initial Brief at 18 (Mar. 8, 2004); Tr. Vol. 8 at 166 - 167.

the 78 customers and the plant transfers from Distribution to Pipeline "appear to be related," ACC challenged the extent of Mr. Greer's knowledge because he was unable to provide a more definitive answer. [602]

ACC concluded that TXU's responses contained misinformation relating to customer counts and varied from 77 customers, 78 customers, and 79 customers. Therefore, ACC's calculations were accurate based upon the assumptions made in reliance upon TXU's responses. ACC argued that the numbers and calculations in ACC Exhibit 14 are correct.[603] ACC Exhibit 14 is TXU's supplemental response to ACC's RFI 5-33, sponsored by TXU witness James A. Greer. ACC Exhibit 14 provides volume deliveries and revenue amount during the 2002 test year for each of 78 customers transferred from Distribution to Pipeline.

Examiners' Recommendation

In GUD 9145, the Examiners merely noted that "if the Dallas South System is used primarily to transport gas, perhaps TXU Gas Distribution should consider transferring that line to TXU LSP. Nevertheless, TXU gas Distribution has not elected to do that in this case." The Examiners in this proceeding acknowledge that this comment is not probative evidence. Nevertheless, the Examiners' recommendation in this proceeding is consistent with the statement in GUD 9145. The Examiners recommend the Commission allow TXU to make the proposed transfers of assets between the two divisions, i.e., Pipeline and Distribution.

A well established ratemaking principle is that costs should be assigned to the customers who benefit from the cost or the service. The concept of transfers of utility plant from Distribution to Pipeline, and vice-versa is consistent with this ratemaking principle. Assets that are used primarily to serve a distribution function should be assigned to Distribution. Assets that are used primarily to serve a transmission function should be assigned to Pipeline. In other words, the primary use of the asset should dictate the classification of that asset as either Distribution or Pipeline.

TXU provided an example in TXU Exhibit 26 at 18 that explains the need for transfers. At the time of the initial installation of pipe in north Tarrant County, the area was rural. The pipe was classified by TXU as transmission facilities. As residential and commercial customers began to populate the area, additional taps were made off the original plant. TXU transferred the plant from Pipeline to Distribution in 2001 when the utility realized that the plant was functioning as a Distribution asset rather than as a transmission asset.

For every transfer, the evidence does not provide a detailed explanation such as the example provided in the above paragraph. However, TXU provided the general criteria used to classify plant[604] and provided listings of the transfers of assets from Pipeline to Distribution and from Distribution to Pipeline. TXU's explanations were that the plant was transferred to align the asset with the primary service that was being

[602] ACC Initial Brief at 18 (Mar. 8, 2004); Tr. Vol. 2 at 26-36; Tr. Vol. 7 at 74.
[603] ACC Initial Brief at 19 (Mar. 8, 2004); TXU Exhibit 39 at 20; ACC Exhibit 14.
[604] TXU Exhibit 26, attachment JAG-R-8.

provided, that Distribution had assumed use of the entire facility or equipment, or that the asset was realigned to connect a mainline customer to town plant.[605]

The evidence presented by ACC does not show that TXU has experienced double recovery. It is possible that the ratemaking process could, at times, result in over-recovery of some items and under-recovery of other items. Even if the evidence showed that the alleged double recovery had occurred, rate making principles do not support reversal of the transfers and perpetuation of the counting. In any case, if these costs were counted in both the city-gate rate and in the municipal distribution rate, the Commission sets rates in accordance with the statute on a forward-going basis.

TXU's proposal to set system-wide rates without setting a city-gate rate will preclude the possibility of double recovery in the future of transferred assets.

The evidence does show that, consistent with the accounting principles of NARUC Plant Instruction 12, TXU transferred at net book value various assets to the appropriate division of TXU Gas. The decisions to transfer plant were based on actual operating considerations. Simultaneously, TXU removed the transferred asset from the rate base of the other division of TXU Gas.[606]

Therefore, the weight of evidence supports TXU's transfer of assets to prevent customers of one division from paying for an asset that is not used and useful to those customers. The Examiners recommend the Commission approve TXU's plant transfers.

13. Poly 1 Pipe/ Safety Compliance Program Invested Capital

Poly 1 Pipe issues are discussed starting on page 13.

14. Poly 1 Pipe Initiative Software

Poly 1 Pipe issues are discussed starting on page 13.

15. Cash Working Capital

<u>Issue</u>

Cash working capital (CWC) is the amount of cash required to fund the day-to-day operations of a utility. Inclusion of an amount of working cash in the rate base is allowed to provide the opportunity for investors to earn a return on the funds they provide as invested capital to meet the daily funding needs of the utility.[607] Although the need for working cash has long been recognized by regulatory bodies and courts,

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[605] TXU Exhibit 26, attachment JAG-R-9.

[606] TXU Reply Brief at 7-8 (Mar. 17, 2004); TXU Exhibit 37 at 5.

[607] *Alabama-Tenessee Natural Gas Co. v. Federal Power Commission*, 230 F.2d 494, 498 (3rd Cir. 1953;) *People's Counsel v. Public Service Commission*, 399 A.2d 43, 46 (D.C. Cir. 1979).

an allowance for CWC is not guaranteed as a component of the rate base and the utility bears the burden of establishing the need for CWC.[608]

Cash working capital requirements may be positive or negative.[609] Positive working capital is investor-supplied; however, a negative amount of working capital reduces the need for investor-supplied funds and occurs when the utility receives customer payments before service is rendered, or when it receives funds before it must satisfy a corresponding liability. To illustrate the concept of cash working capital, if one assumed that the utility paid for natural gas before it is paid for the natural gas by its customer, then the utility would be using positive cash working capital, i.e. funds from its investors, to pay for the natural gas until the customer made payment to the utility. In this example, the investor would have an expectation of receiving a reasonable return on their investment. If however, the consumer paid the utility in advance for use of the product, the utility has a negative cash working capital and the investor would have no expectation of return because invested capital was not being used. Ultimately, a determination of working capital is an exercise of discretion as to what particular method yields the most fair and equitable result in each case.[610]

In order to determine the appropriate level of CWC to fund its day-to-day operations, TXU performed two lead-lag studies (one for TXU Gas - Distribution and one for TXU Gas - Pipeline) based on its test year ending December 31, 2002.[611] The purpose of a lead-lag study is to establish the net amount, if any of CWC supplied by investors, and to identify the level of capital investment that must be included in the rate base so that the total of rate base components equals the total capital provided by investors.[612]

Given the dynamic nature of fund inflows and outflows to assess an appropriate level of working cash in daily operations, a lead-lag study is commonly employed to arrive at the required level of working cash. A lead-lag study is an analysis that matches recurring fund inflow and outflow patterns to each other to identify working capital requirements over a designated time interval.

In arriving at a method for the utility's lead-lag studies, the utility proposed the use of the guidelines found in Public Utility Commission's Rule at 16 TEX. ADMIN. CODE §25.231, the only rule concerning lead-lag studies that is propounded by a Texas regulatory agency. [613] No intervening party opposed the application of 16 TEX. ADMIN. CODE §25.231, and ACC intervening party witness Tucker agreed that the rule provide an appropriate guidance for parties in this case.[614] In the circumstances where 16 TEX. ADMIN. CODE §25.231 did not provide guidance, TXU implemented the findings from the Commission's Final Order in GUD 9145, the Utility's most recent rate proceeding before the Commission.[615]

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[608] *Southern Union Gas Co. v. Railroad Commission of Texas*, 701 S.W.2d 277 (Tex. App.—Austin 1986) (Gas utility failed in its burden of proof regarding its working capital needs); *Peoples Counsel v. Public Serv. Comm'n* 399 A.2d 43, 45.

[609] *Cincinnati Gas & Elec. Co. v. Public Util. Comm'n*, 620 N.E.2d 821 (Ohio 1993).

[610] *General Tel. Co. v. Arkansas Pub. Serv. Comm'n*, 23Ark.App 73, 744 S.W.2d 392, 397 (Ark. Ct. App.) *aff'd* 295 Ark 595, 751 S.W.2d 1 (1988).

[611] TXU Exhibit 21 at 4.

[612] TXU Exhibit 21 at 4.

[613] TXU Exhibit 21 at 5.

[614] ACC Exhibit 2 at 10.

[615] TXU Exhibit 35 at 6

Based on the results of TXU's proposed lead-lag studies, the CWC requirement for TXU Gas - Distribution is negative $53,963,727 and the CWC requirement for TXU Gas - Pipeline is negative $1,711,028.[616] The CWC amounts identified by the TXU were adjusted from initial stated requirements of negative $53,763,162 and negative $3,224,772 for Distribution and Pipeline respectively.[617]

TXU's lead-lag studies were challenged by ACC and Dallas. The intervening parties took divergent positions. ACC concluded that the TXU's studies should be determined to be "so flawed as to be unreliable" and therefore pursuant to 16 TEX. ADMIN. CODE §25.231, the CWC should be set equal to an amount of negative one-eighth of O&M expense including gas cost.[618] Dallas did not find the study "flawed," but instead recommended adjustments to TXU's CWC request that result in overall changes resulting in CWC of negative $85,924,561 for Distribution and negative $5,157,255 for Pipeline.[619]

The lead-lag study evaluated funds and activities in 11 categories for Distribution, and 8 categories for Pipeline. Specifically, the lead–lag study evaluated funds and activities in categories for: Operation and Maintenance (O&M) costs, Current and Deferred Federal Income Taxes, Taxes other than income taxes, Depreciation Expense, Return, Average Daily Bank Balances, Working Funds, and Other.[620] Distribution further added to these categories for Purchased Gas Cost, Pipeline Costs, and Interest on Customer Deposits.[621]

Based on precedent established in GUD 9145, the TXU proposed allowances for Deferred Federal Income Taxes, Depreciation Expense, and Return to $0.[622]

ACC recommended that TXU receive an amount equal to negative one-eighth of O&M expense including gas cost as the appropriate level of CWC. The basis for this contention is 16 TEX. ADMIN. CODE §25.231(c)(2)(B)(iii).[623] In support of this contention, ACC identified the following problems with the TXU's lead-lag studies: (1) failure to use weighted dollar days for revenue lag in the TXU Gas - Distribution study; (2) use of non-cash items in the calculation of weighted dollar days for revenue lag in the TXU Gas - Pipeline study; (3) O&M expense lag calculations should consistently use the mid-point of the service period and dollar weighted lag days; (4) income tax payment patterns do not reflect actual payment patterns; and (5) Bank Balances and Working Funds should not be included in CWC, based on prior Commission rulings.[624]

Dallas raised several issues with TXU's Distribution and Pipeline studies for lead days calculated for the following expense categories: Purchased Gas Costs, Payroll, Affiliated Company Payments, Third Party Invoices, Taxes Other Than Income Taxes, Franchise Fee Payments, Average Daily Bank Balances,

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616 TXU Exhibits 6, 7, 61, Schedules E-8(D) & E-8(P).
617 TXU Exhibit 21 at 5.
618 ACC Exhibit 2 at 34.
619 Dallas Exhibit 1 at 96.
620 TXU Exhibit 34, attachment ALW-R-2 at 139.
621 TXU Exhibit 34, attachment ALW-R-2 at 33.
622 TXU Exhibit 21 at 15.
623 ACC Exhibit 2 at 33.
624 ACC Exhibit 2 at 14.

Pipeline O&M costs, and methodology for the sale of Accounts Receivable (securitization costs).[625]

a. Use of Weighted Dollar Days in Revenue Lag Calculation

Revenue lag represents the amount of time between the delivery of service to customers and the receipt of the related revenues for such service.[626] In the TXU's calculation of revenue lag days for the Distribution lead-lag study, a weighted-dollar-day approach was not used. ACC argues that a weighted-dollar-day approach was appropriate, was used for the Pipeline lead-lag study, and requested that the TXU provide a calculation in weighted-dollar-days of Distribution revenue lags, which was subsequently provided and incorporated into the TXU's calculation of cash working capital. ACC maintained that the initial lack of a weighted-dollar-day approach to determining the revenue lag days in the Distribution lead-lag study impugns the reliability of the study. TXU maintained that, while it is acceptable alternative method for determining the revenue lag days, a weighted-dollar-day approach is not addressed under 16 TEX. ADMIN. CODE §25.231, or TXU's most recent rate case, GUD 9145, which TXU used as a basis for preparation of the lead-lag studies. The Examiners agree with the utility that use of a dollar-day weighting is not compelled under the framework of either the PUC rule or GUD 9145; however dollar-day weighting of revenue lag days is preferable for Distribution and is consistent with TXU's calculation of revenue lag days for Pipeline CWC.

<u>TXU's Position</u>

Revenue lag represents the amount of time between the delivery of service to customers and the receipt of the related revenues for such service. The use of weighted dollar days in this calculation is not addressed by 16 TEX. ADMIN. CODE §25.231. Accordingly, consistent with TXU's overall approach, the utility provided testimony that TXU implemented the methodology approved in its most recent Commission rate case, GUD 9145. In GUD 9145, the utility did not use weighted dollar days and the Commission approved the utility's methodology. [627] Nonetheless, TXU Gas subsequently provided the weighted dollar day calculation when requested by ACC, which TXU noted actually resulted in an increase in TXU Gas - Distribution CWC. [628]

ACC also asserted that TXU erred by failing to use weighted dollar payment calculations for O&M expense lags. However, the utility argued that 16 TEX. ADMIN. CODE §25.231 does not require the use of weighting of dollar days in calculating O&M expense lag and therefore, consistent with the overall approach to the utility's lead-lag studies, TXU followed the guidance provided in the Commission's Final Order in GUD 9145, TXU Gas' most recent contested case at the Commission. [629] In that docket, TXU did not use a dollar day weighting approach and its methodology was not at issue. TXU contends in this proceeding that reasonable minds may dispute the appropriate methodology; however, such an approach cannot be considered an error on which a study is considered flawed.[630]

[625] Dallas Exhibit 1 at 95; Dallas Exhibit 1, attachment JP-9 and JP-10.
[626] TXU Exhibit 21 at 10.
[627] TXU Initial Brief at 20 (Mar. 8, 2004).
[628] TXU Exhibit 35 at 13.
[629] TXU Exhibit 35 at 18-19.
[630] TXU Initial at 21 (Mar. 8, 2004).

TXU calculated and provided to ACC the weighted dollar day calculation requested, and it is the utility's position that using weighted-dollar-days is an acceptable alternative method for calculating lead-lag days in these areas.[631]

Intervenors' Position

ACC asserted that TXU initially failed to use weighted dollar-days for calculating its revenue lag in the Distribution lead-lag study and to determine payment lags to affiliate companies. ACC noted that TXU revised its lead-lag study to use weighted dollar-days for its Distribution study.[632] ACC further asserted that if it had not raised the issue, it is unlikely that TXU would have provided an expense lag calculated using weighted dollar-days.[633] ACC argued that TXU denied that it was a mistake to not use weighted dollar days, alleging that this was merely a disagreement over the methodology to be used. Thus, even though TXU eventually agreed with ACC that weighted dollar days should be used, the underlying data used by TXU are still suspect and unreliable.[634]

Examiners' Recommendation

The evidence shows that a weighted dollar-day revenue lag calculation is not the only methodology that may be employed. TXU subsequently provided a dollar-day weighted calculation for the Distribution lead-lag study which provides a reasonable basis for calculating revenue lag days.

Though never overtly stated, it is implicit in ACC's argument that an expense lag must be calculated using a weighted dollar-day method to be valid. However, TXU has established that its methodology was reasonable, i.e., using the PUC rule for initial guidance and then looking to precedent in GUD 9145 when the rule was silent. TXU provided the expense lag calculation using the weighted dollar-day approach when requested by ACC and stated that this methodology provided an acceptable alternative. While the Examiners agree that a dollar-weighted method is appropriate, especially in the interests of consistency when other elements of the lead-lag study use it, the evidence presented by ACC does not establish a requirement for a weighted dollar-day approach in the lead-lag study. In the absence of requirement under 16 TAC §25.231 or under Railroad Commission rate case precedent, and given that TXU revised CWC calculations incorporating the use of weighted dollar-days, the TXU's lack of a weighted dollar-day approach in calculating revenue and expense lags in its initial filing does not invalidate the utility's lead-lag study. The evidence shows that TXU's revisions to incorporate weighted dollar-days in its calculation of revenue and expense lag days are reasonable.

b. Non-Cash Items

TXU's Position

The utility asserted that payments between affiliated companies where cash trades hands via accounting entries without the issuance of a check, or the payment of cash, constitute bona fide transactions, just the same as if an actual physical funds transfer had taken place.[635] While TXU acknowledged 16 TEX. ADMIN. CODE §25.231 provided that non-cash items will not be considered for purposes of CWC, argued that the

[631] TXU Initial Brief at 21 (Mar. 8, 2004).
[632] ACC Exhibit 2 at 15.
[633] ACC Initial Brief at 28 (Mar. 8, 2004).
[634] ACC Initial Brief at 29 (Mar. 8, 2004).
[635] TXU Exhibit 35 at 15.

rule does not identify accounting transactions between affiliates as "non-cash" items. All transactions among the utility's various subsidiaries and divisions are "non-cash" accounting transactions.[636] However, the TXU maintained that these transactions are not the transactions 16 TAC §25.231 seeks to exclude. TXU further argued that it would not make sense, nor would it be efficient or beneficial to ratepayers, for these companies and divisions to actually write checks to each other, as such an approach would have no effect to CWC other than to increase it for the amount of check float. [637]

Intervenors' Positions

ACC argued that in accordance with PUC rule 25.231(c)(2)(B)(iii)(IV)(-a-), it is inappropriate to use non-cash items in the calculation of cash working capital.[638] The intervening party alleged the utility admitted that it provided revenue estimates for accounting transactions, which ACC contends are non-cash transactions. The intervening party further argued that these non-cash transactions, have significantly different lead-lag days and distort the cash needs of the utility resulting in an unreliable lead-lag study. Therefore, because all of the transactions between TXU Gas and its affiliates are non-cash transactions, these transactions should be disallowed in its lead-lag studies.[639]

Examiners' Recommendation

The Examiners find that the evidence shows that inclusion of accounting entry payments is reasonable. The evidence does not show accounting entries payments between affiliate companies be classified as non-cash items.

The Examiners recommend that non-cash transactions not be excluded from the calculation of cash working capital. The Examiners note that while PUC Rule 25.231 states that all non-cash items should not be considered from the lead-lag study,[640] the utility's inclusion of non-cash accounting transactions among affiliate companies is appropriate for an evaluation of the cash working capital allowance in rate base, because in this proceeding TXU established that the transactions constitute a pattern of recurring payments which, although transacted electronically among affiliated companies, effectively serve the same purpose as cash transactions.[641]

c. Mid-Point of Service Period

TXU's Position

TXU provided testimony that TXU used the definition of service period that was established in GUD 9145, which recommended that the starting point of the lead period should be identified by the invoice date and that the end date should be the due date.[642] TXU argued that because PUC Rule 25.231 provided no guidance on this issue, its use of the invoice date instead of the mid-point of the service period is supported by the Commission's decision in GUD 9145 and is appropriate. [643] TXU further argued that compliance

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636 TXU Exhibit 35 at 15.
637 TXU Exhibit 35 at 15.
638 ACC Exhibit 2 at 21.
639 ACC Exhibit 2 at 21.
640 16 TEX. ADMIN. CODE §25.231 (c)(2)(B)(iii).
641 TXU Exhibit 35 at 15.
642 TXU Exhibit 34 at 7.
643 TXU Exhibit 34 at 8.

with the most recent order of the Commission cannot be considered an error on which a study may be considered flawed.[644]

ACC and Dallas's Positions

ACC argued that the use of the mid-point of the service period as the beginning point is appropriate. Other O&M Expenses April 16, 2004 is the only expense lag in TXU's studies -- except for federal income taxes -- that does not use the mid-point of the service period in the calculation of payment lags.[645] ACC argued that the use of the invoice date can result in unreasonable payment lags. ACC stated that the use of the mid-point of the service period has been found to be a reasonable method in previous filings in Texas.[646] ACC argued that TXU's use of the invoice date as the beginning point for the calculation of payment lag days distorts the picture of the utility's actual payment practices.[647] As described by ACC, even though TXU was seriously delinquent in the payment of rent on a communications tower, the utility's use of the invoice date (of a past due invoice showing the utility to be in arrears for over three years), resulted in a payment lag of only 15 days, because payment was made only 15 days after the past due notice was dated. This resulted in an artificial increase in the cash working capital needs of the utility.[648]

ACC argued that TXU's use of the invoice date in this docket is contrary to the PUC's practice. ACC urged that the Railroad Commission's determination in GUD 8976 is more appropriate than the invoice date in calculating lag periods.[649] In GUD 8976, the Commission based the period on the date services were received. Dallas argued that its review of the sample taken for the third party invoices revealed a tremendous number of errors, including TXU's use of the invoice dates as the service periods. Dallas joined in ACC's contention that the lead period should be from the midpoint of the service period to the due date.[650]

Examiners' Recommendation

The evidence shows that the starting point of the lead period should be identified by the invoice date and the end date should be based on the due date. The evidence does not show that the mid-point of the service period must be used in O & M expense lag day calculations.

It is reasonable for TXU to use the service period as defined in GUD 9145, which specified the beginning of the lead period as the invoice date and the end period as the due date.[651] The evidence shows this methodology would define the actual service period, therefore it is a reasonable basis for the service period calculation.

The Examiners considered Dallas's testimony that TXU's study contained numerous errors. The evidence does not show that TXU's methodology was incorrect. The evidence does not support a reversal of the service period definition. The evidence shows that TXU's methodology was reasonable.

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[644] TXU Initial Brief at 21 (Mar. 8, 2004).
[645] ACC Exhibit 2 at 28.
[646] ACC Exhibit 2 at 28.
[647] ACC Initial Brief at 30 (Mar. 8, 2004).
[648] ACC Exhibit 2 at 29.
[649] ACC Exhibit 2 at 30.
[650] Dallas Exhibit 1 at 101-102.
[651] GUD 9145-9148 at 27.

d. Purchased Gas Cost

TXU recommended 48.269 lead days for purchased gas cost during the test year in its Distribution lead-lag study.[652] Dallas argued that purchased gas cost should reflect subsequent changes in the market price of gas since the test year and that 48.335 lead days more accurately reflects actual expense lead days.[653] The Examiners recommend 48.335 lead days for purchased gas costs incurred during the test year.

TXU's Position
TXU argued that lead-lag studies reflect the cost of purchased gas during the test year, and that Dallas ignored the test year concept. TXU recommended increasing the purchased gas cost used in the development of CWC to reflect average costs through October 2003. TXU argued Dallas's recommendation is faulty for three reasons. First, Dallas's proposal violated the test year concept and the matching principle. Second, Dallas's proposal was piecemeal ratemaking. Dallas adjusted the value of one item (Purchased Gas Cost), but failed to make conforming adjustments to the values of other related items in the test year, such as Working Gas in Storage, Lost and Unaccounted for Gas, and Line Pack. Third, the price of gas changes constantly. Gas costs increased after the test year, but are presently declining. TXU noted that ACC recommended a reduction in test year gas costs in contradiction to Dallas's recommended increase.[654] The constant variation in the cost of gas supports TXU's use of the test year numbers because they capture the cost of gas incurred at the same time as all of the other elements that are included in the test year. Accordingly, TXU argued that Dallas's recommendation should be rejected.[655]

Intervenor's Position
In pre-filed testimony, Dallas argued that in order to reflect the conditions during the period that rates will be in effect, to reflect the changes in costs that TXU is experiencing, and to accommodate the leads and lags associated with those changes, a more current cost of gas should be used.[656] Dallas noted that gas costs have increased significantly since the test year, and that the lead period also must be adjusted to reflect the actual payment period. Dallas based the need for the lead day adjustment on the actual payment pattern for purchased gas for the month of April during the test year. In April 2002, the payment was due on the 25th of the following month.[657] Dallas argued that under the terms of the supplier contract, when the 25th falls on a weekend TXU is entitled to make payment on the next following business day. In this case, payment was due the 27th of May 2002.[658] In calculating the lead period for this expense Dallas stated that TXU used the 24th of May as the basis for the lead day calculation which should be changed to the 27th for consistency with TXU's actual payment patterns. This change would then reflect true expense lead days. The additional 3 days for the subject month increases the overall lead days by .1645 days thereby increasing the overall lead days to 48.4335 days.[659]

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652 TXU Exhibit 34, attachment ALW-R-2 at 33.
653 Dallas Exhibit 1 at 96.
654 TXU Exhibit 34 at 3-4.
655 TXU Initial Brief at 30 (Mar. 8, 2004).
656 Dallas Exhibit 1 at 96.
657 Dallas Exhibit 1 at 97-98.
658 Exhibit 1 at 97-98.
659 Exhibit 1 at 98.

Examiners' Recommendation
The evidence shows that the purchased gas cost should reflect the test year cost of gas with lead days of 48.4335. The evidence does not support Dallas's proposal to increase the price.

The evidence shows Dallas's calculation of 48.4335[660] expense lead days for purchased gas cost to be reasonable and to most accurately reflect actual test year purchased gas cost lead days. The calculation corrects the associated expense lead days for the month in question and corrects overall expense lead days. The Examiners' recommendation is consistent with TXU's treatment of other invoices where the due date falls on non-business days.[661]

The evidence also shows that TXU's proposed use of test year purchased gas cost is reasonable. It is reasonable for TXU to use the test year to determine the data used for developing the rate base.[662] The evidence shows that another method besides test year purchased gas cost would be inconsistent with other components of rate base, resulting in inherently dissimilar rate base components. Accordingly, the Examiners recommend that the purchased gas cost incurred during the test year be the basis of this CWC expense calculation.

e. Affiliated Company Payments

TXU proposed expense lead days of 26.439 in the Distribution lead-lag study and 26.438 in the Pipeline lead-lag study for payments made by TXU Gas to its affiliates, TXU – Business Services and TXU – Pipeline.[663] The affiliated company payments to TXU - Pipeline apply to the Distribution lead-lag study. TXU argued that this lead day period, based on payment made on the eighth working day of the following month for which services are received, is standard practice for TXU and correctly reflects the actual pattern of payments as they are in TXU operations for purposes of the lead-lag study.[664] Dallas argued that the proposed expense lead days for the two affiliates are inconsistent with payment patterns made to other affiliated companies and are an arbitrary choice made by TXU without justification.[665]

TXU's Position
TXU argued that it has properly reflected the actual pattern of payments between TXU Gas - Distribution and TXU Business Services and between TXU Gas – Distribution and TXU Gas – Pipeline in its lead-lag studies for both Distribution and Pipeline.[666] TXU testified that such payments are made on the eighth day of the month following the month in which the services were rendered, which is consistent with TXU's practice and with common industry practice.[667] TXU stated that Dallas's recommendation – – that the Commission disregard the actual pattern of payment in favor of a hypothetical payment pattern – – has no basis in fact or actual practice. TXU maintained that the lead-lag studies were designed to reflect the actual

660 Exhibit 1 at 98.
661 Dallas Exhibit 1 at 98.
662 TXU Exhibit 34 at 3.
663 TXU Exhibit34, attachment ALW-R-2 C-4a at 74 and B-4b at 167.
664 TXU Exhibit 35 at 16.
665 Dallas Exhibit 1 at 100.
666 TXU Exhibit 34 at 5; TXU Exhibit 35 at 16.
667 TXU Exhibit 35 at 16.

test year operations of TXU, adjusted for known and measurable changes. TXU argued that Dallas's proposal would reject actual test year operations and replace them with hypothetical payment periods. TXU argued that Dallas provided no evidence to support this method.[668]

In response to ACC's contention that TXU erred in initially not providing a dollar-weighted calculation of expense lag days to affiliated companies, the utility stated that using weighted dollar days is an acceptable alternative method for calculating lead-lag days in these areas.[669]

Dallas and ACC's Position

Dallas disagreed with TXU's use of the payment to affiliated companies made on the 8th working day for TXU Business Services and Pipeline. Dallas argued that this period of time is much shorter than the period utilized for other affiliated companies and for non-affiliated companies.[670] Dallas revised the study to reflect the use of the same number of days for TXU Business Services and Pipeline as TXU used for other affiliated companies or 42.708 lead days for this portion of other O&M.[671] Dallas's noted that this issue also applies to the TXU – Pipeline lead-lag study for its payment lead days to TXU – Business Services. Dallas argued that the TXU –Pipeline lead lag study should also be placed under the same 42.708 lead day calculation, which would provide consistency with TXU's payments to other affiliates.[672]

ACC argued that TXU erred by failing to use weighted dollar-day payment lags for the affiliate company payments.[673] However, TXU Gas performed the calculations necessary to comply with ACC's request and modified the results of the lead-lag studies accordingly.[674]

Examiners' Recommendation

The evidence shows 26.439 days for affiliated company payment lead days are appropriate. The evidence does not support modification of the payment lead days for TXU Business services and for TXU Pipeline.

The Examiners recommend the expense lead days of (26.439) lead days for payments to TXU – BS and TXU – Pipeline in the case of the Distribution lead-lag study, and TXU – BS in the case of the Pipeline lead-lag study. TXU provided probative testimony of witnesses Warren and Joyce to rebut Dallas's proposed change to the expense lag days for payment to the two affiliates.[675] Dallas's position is based on using a lag day calculation that is consistent with that used for payment of other affiliate companies.[676] This calculation was derived by TXU and is not merely hypothetical. Nevertheless, evidence shows Dallas's proposal to be inconsistent with the test year concept, and does not reflect the actual payment patterns. The Examiners find that the lead-lag studies provide a reasonable calculation of lead days for affiliated company payments.

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[668] TXU Exhibit 34 at 6.
[669] TXU Exhibit 35 at 17.
[670] Dallas Exhibit 1 at 100.
[671] Dallas Exhibit 1 at 101.
[672] Dallas Exhibit 1 at 109-110.
[673] ACC Exhibit 2 at 25.
[674] TXU Exhibit 35 at 17.
[675] TXU Exhibit 34 at 6.
[676] Dallas Exhibit 1 at 101.

f. O&M Expense Sample

TXU calculated 40.3 lead days for the category of Other O&M expenses in its initial filing.[677] After revision for correction of errors, TXU's calculation changed to 47.560 lead days. Dallas argued that TXU's lead day calculation was erroneous and misstated the service period definition used for determining lead days.[678] The Examiners recommend that TXU's calculation of expense lead days, as revised is reasonable.

TXU's Position
TXU provided detailed information establishing the appropriate lead days for third party O&M expenses.[679] TXU argued its lead lag studies were supported with documentary evidence. TXU noted Dallas's challenges are to electronic invoices, which Dallas never reviewed.[680]

TXU argued that Dallas's recommendation are based on personal preference, that the recommend methodology is inconsistent with GUD 9145. In GUD 9145, the service period definition used the invoice date for a beginning and check date for the end. TXU also argued that Dallas incorrectly added check float days to electronic transactions that clear on the same day.[681] TXU asserts that the revisions proposed by Dallas are inappropriate because they do not reflect consistency with GUD 9145 and are based on insufficient understanding of TXU's transactions.[682]

Dallas's Position
Dallas noted that there were a tremendous number of errors in the utilization of the sample taken for the third party invoices.[683] Dallas explained that for this expense category, every invoice is not studied, but a sample is taken. In this case, a sample of 150 invoices was used. Dallas asserted that a competent lead-lag study could use that sample to determine the appropriate number of days for the expense category.[684] Dallas argued that the deficiencies in the TXU study included insufficient material for over 75 percent of the invoices, no backup for electronic data invoices (EDI). Dallas argued these flaws destroyed any credibility for TXU's study and conclusions.[685] Dallas observed that TXU used the invoice date as the service period. TXU reported it only had EDI data, when in fact it had an invoice.[686] Dallas also identified the error in Invoice No. 80 in which the TXU relied on the service date.[687]

Dallas also asserted that TXU misstated the effect of correction of errors. TXU claimed that the correction of the errors increased the cash working capital. Dallas argued that the claimed change was actually a change in method, not merely a correction of errors.[688] Dallas argued that its revisions correctly applied

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[677] Dallas Exhibit 1 at 101.
[678] Dallas Exhibit 1 at 102.
[679] TXU Exhibit 34 at 9.
[680] TXU Exhibit 34 at 9.
[681] TXU Exhibit 34 at 9.
[682] TXU Exhibit 34 at 10.
[683] Dallas Exhibit 1 at 101.
[684] Dallas Exhibit 1 at 101.
[685] Dallas Exhibit 1 at 101.
[686] Dallas Exhibit 1 at 101.
[687] Dallas Exhibit 1 at 103.
[688] Dallas Initial Brief at 25 (Mar. 8, 2004).

the days to the Other O&M sample category, properly applied those amounts to the study, resulted in an increase of 35.347 days lead time in the other O&M sample category, and which reduced CWC.[689]

Examiners Analysis

The evidence shows that 47.560 lead days, as proposed by TXU, is reasonable for Distribution Other O & M expenses as determined by TXU's sample methodology.

TXU relied on GUD 9145 to define the service lead periods for third party transactions. The invoice date and payment due date define the service lead period.[690] Dallas's approach used an actual stated service period, when available, from the invoice to define lead days.[691] The evidence shows Dallas's methodology is not unreasonable. Dallas's methodology may add greater precision to the calculation of expense lead days by using the actual service periods, when known, for the invoice sample. The evidence shows that because the service period is often unspecific, this method will provide only an approximation of the service lead day calculation. The evidence shows a narrow sample of invoices. Therefore, inconsistent methods may distort results. The evidence shows TXU based its lead day calculation on a consistent service period lead day definition in the Distribution and Pipeline lead-lag studies. The Examiners find TXU's proposal is reasonable.

g. Payroll

TXU's Position

TXU argued that it does not accrue sick days and therefore an employee, when severed, is not paid for sick time; no such time has been accrued.[692] Dallas recommended an adjustment to Payroll lead days based on TXU's position that it does not accrue sick days for its employees. TXU stated that Dallas's adjustment would not reflect the actual operations of TXU Gas at the current time, and that Dallas cited no authority or support for its proposal.[693] TXU argued that Dallas ignored the actual operations of the utility in proposing a change in lead days to 28.517.[694]

Dallas's Position

Dallas argued that TXU miscalculated the lead days associated with payroll expense.[695] In order to properly account for vacation, sick leave, and check float, the number of lead days should be increased from 24.705 to 28.517.[696] Dallas's revised calculation was performed on the basis of correcting normalized vacation pay to 7.7 percent. Based on average employee tenure of 17 years, Dallas estimated sick leave payroll on the level TXU identified in GUD 8976 and on TXU's check float calculation.[697]

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689 Dallas Exhibit 1 at 105.
690 TXU Exhibit 34 at 8.
691 Dallas Exhibit 1 at 104.
692 TXU Exhibit 34 at 11.
693 TXU Exhibit 34 at 11.
694 TXU Initial Brief at 31-32 (Mar. 8, 2004).
695 Dallas Exhibit 1 at 99.
696 Dallas Exhibit 1 at 99.
697 Dallas Exhibit 1 at 99.

Examiners' Recommendation
The evidence shows TXU's calculation of expense lead days for payroll is reasonable. The evidence does not support a change to the payroll lead days.

The 24.705 payroll expense lead days proposed by TXU are reasonable and should be adopted. The evidence shows that Dallas's calculation was based on information extrapolated from GUD 8976,[698] which is materially dissimilar to the test year data used in this proceeding. TXU's evidence established that because it does not pay for sick time upon an employee is severance, there is no reasonable basis for including it in the calculation.

h. Sales of Accounts Receivable (Securitization)

Receivables securitization program is a method by which a company sells its accounts receivables to a third party for cash, thereby accelerating the receipt of cash collected.[699] This acceleration of cash collection reduces working capital requirements as it provides the benefit of immediate returns on receivables sold. TXU testified that it does not unilaterally elect to securitize any level of its receivables, because the amount of cash received is a function of a credit-based filter process used to determine the receivables to be sold.[700] The percentages of receivables sold reflected TXU Gas' pro rata share of cash advanced for high-quality filtered receivables as a percentage of the total receivables sold.[701] The Examiners agree that TXU's basis for adjusting its receivables lead days under the utility securitization program was reasonable and therefore need not be modified to comply with an approach assuming 100 percent securitization.

TXU's Position
TXU testified that a receivables securitization program requires a willing buyer or buyers. There are four purchasing entities in the program in which TXU Gas participates.[702] TXU noted that it does not control the actions of these entities and must negotiate the parameters of each program. The program size is determined in conjunction with the entities that desire to purchase the receivables, not solely by TXU Gas, and is generally a function of four determinants: (1) the credit quality of the receivables to be purchased; (2) the credit quality of the utility selling the receivables; (3) the amount of extra accounts receivable or reserves required to ensure purchasers are able to collect the full amount advanced; and (4) the month-to-month sustainable amount of saleable receivables given the previous three parameters.[703] TXU summarized that it did not artificially limit the size of the program. The size of the program is determined through careful consideration of all of the foregoing factors in conjunction with the purchasing entities.[704]

TXU noted that several factors impact the amount of receivables for which TXU Gas may receive immediate payment. First, the purchasing entities require that the receivables be "filtered." Filtering is a standard market process utilized to eliminate receivables with a higher likelihood of non-collection in

[698] Dallas Exhibit 1 at 99.
[699] TXU Exhibit 33 at 4.
[700] TXU Exhibit 33 at 4.
[701] TXU Exhibit 33 at 4.
[702] TXU Exhibit 33 at 5.
[703] TXU Exhibit 33 at 6.
[704] TXU Exhibit 33 at 8.

order to ensure the purchased receivables achieve a Standard & Poors rating of 'A.'[705] Examples of filtering include, but are not limited to the exclusion of: (1) individual customer accounts representing more than 2 percent of total receivables; or (2) accounts with more than 20 percent past due for more than 90 days. Filtered receivables increase collection risk and must be set aside when determining the cash to be tendered for sold receivables.[706] Second, the purchasers require that a certain amount of receivables be effectively held as collateral until the purchased receivables are paid. This is known as the "reserve protection requirement."[707] Combined, TXU argued, these two factors decrease the amount of receivables for which TXU Gas may receive immediate cash at any given time.[708]

TXU stated that it cannot securitize 100 percent of its accounts receivable because of the filtering process and reserve protection requirements.[709] TXU also noted that no purchaser would fund dollar for dollar a receivables program for which the purchaser has no guarantee of collection. TXU argued that the purchaser considers the time value of money.[710] TXU argued that the intervening parties' assumptions about its program are incorrect and Dallas's proposals should be rejected.

Dallas's Position

TXU securitizes a portion of the revenues billed for Distribution and Pipeline. This process reduces the costs incurred by customers associated with the revenue lag for the period between issuing bills to customers until TXU receives cash from customers for such bills.[711] Dallas observed that TXU Gas securitized only 58.579 percent of Distribution and 50.86 percent of Pipeline accounts receivables.[712] Dallas argued that other utilities have securitized 100 percent of the accounts receivable, and TXU's failure to securitize the full level of revenues for Distribution and Pipeline is inappropriate and unreasonable. Dallas stated that its correction would reduce Distribution invested capital by approximately $18 million and Pipeline invested capital by approximately $5.3 million.[713]

Examiners' Recommendation

The evidence shows TXU appropriately included sales of receivables. The evidence does not support that cash working capital must be based on 100 percent securitization of accounts receivable for Pipeline and Distribution.

The Examiners recommend including securitization of receivables in the calculation of the cash working capital allowance for TXU – Distribution and TXU – Pipeline as proposed by TXU. TXU presented evidence showing that its basis for adjusting receivables lead days for both Distribution and Pipeline entities from the actual percentages of receivables sold is reasonable. Dallas argued that other companies have securitized 100 percent of receivables, but presented no probative evidence for this assertion. The Examiners agree that if TXU were able to provide for full securitization of its receivables, it would be to

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[705] TXU Exhibit 33 at 5.
[706] TXU Exhibit 33 at 5.
[707] TXU Exhibit 33 at 7.
[708] TXU Exhibit 33 at 8.
[709] TXU Exhibit 33 at 10.
[710] TXU Exhibit 33 at 10.
[711] Dallas Exhibit 1 at 112.
[712] Dallas Brief at 27 (Mar. 8, 2004).
[713] Dallas Brief at 27 (Mar. 8, 2004).

the mutual benefit of its ratepayers and itself.[714] The evidence presented shows a reasonable calculation of TXU's receivables expense lead days, based on the securitization program in place during the test year.

i. Payroll Taxes

Payroll taxes are a component element of the cash working capital expense category of Taxes Other than Income Taxes for both the Distribution and Pipeline lead-lag studies.[715] As in the case of the Payroll expense lead days, the lead day calculation for Payroll tax is disputed by Dallas. Dallas proposed to adjust payroll tax expense days by incorporating vacation related payroll adjustments into the lead time as TXU has done with payroll lead days.[716] The differences in lead times by adjusting for vacation lead days is summarized in the following table. The Examiners recommend the expense lead days as proposed by Dallas be adopted.

Summary Table: Number of Lead Days

Distribution	TXU	Dallas	Examiners Proposal
FICA	(14.245)	(28.295)	(28.295)
Federal Unemployment	(97.181)	(111.231)	(111.231)
State Unemployment	(91.563)	(105.613)	(105.613)
Pipeline:	TXU	Dallas	Examiners Proposal
FICA	(14.273)	(28.323)	(28.323)
Federal Unemployment	(87.476)	(113.839)	(113.839)
State Unemployment	(82.220)	(108.583)	(108.583)

<u>TXU's Position</u>

TXU stated that the issue raised by Dallas does not reflect actual TXU operations and thus argued it should be denied.[717]

<u>Dallas's Position</u>

Dallas argued that the calculation of the lead days for payroll taxes must match the lead days for payroll.[718] Dallas argued that TXU did not recognize the longer lead time for the payroll taxes associated with vacation pay for the payroll taxes associated with vacation – – the federal and state unemployment taxes – – and proposed that the vacation adjusted lead day calculation of 24.705 should be incorporated in each of the categories for payroll taxes for both Pipeline and Distribution.[719] Dallas provided specific revised lead day calculations for Distribution, which Dallas derived by summing the original lead day calculation

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714 Dallas Exhibit 1 at 114.
715 TXU Exhibit 21 at 15.
716 Dallas Exhibit 1 at 106.
717 TXU Exhibit 34 at 11.
718 Dallas Exhibit 1 at 106.
719 Dallas Exhibit 1 at 106.

with the 24.705 vacation lead day adjustment and 1.932 lead days identified with the time from check issuance to deposit, less 3.191 check float lead multiplied by the 16.532 percent of payroll paid by check (Distribution). Using similar methodology, Dallas also provided calculations for the lead day periods for payroll taxes in the Pipeline lead-lag study.[720]

Examiners' Recommendation

The evidence shows that payroll tax expense lead days should include vacation adjusted payroll as provided in the lead-lag studies for Distribution and Pipeline.

TXU did not directly address Dallas's contention that a longer lead time for payroll taxes was warranted to adjust for vacation time.[721] TXU argued for the rejection of Dallas's proposal on the basis of non-accrual of sick time. However, this was not the issue raised by Dallas in this instance. The evidence shows Dallas's argument for an adjustment in payroll tax lead days to reflect consistency in the application of vacation lead days for payroll is reasonable. The Examiners recommend the proper level of lead days as proposed by the City of Dallas for payroll taxes be adopted.

j. Franchise Fees

TXU calculated (46.534) lead days for Local Gross Receipts Tax or franchise fees, during the test year in the Distribution lead-lag study.[722] TXU stated that TXU Gas correctly calculated the service period for local gross receipt taxes (or franchise fees) lag days, and that the utility excluded pre-payments from the total calculated amount to be applied to CWC.[723] Dallas argued that TXU included a portion of its payments as pre-payments, which resulted in an incorrect calculation of lead days. Dallas recommends (106.617) lead days.[724] The Examiners recommend that the (106.617) lead day calculation be adopted.

TXU's Position

TXU argued that TXU's franchise agreements may include both a privilege period and a fee calculation period.[725] The privilege period is the time period over which the governmental authority grants TXU Gas the right to use the authority's streets and alleyways. In exchange, the TXU pays a franchise fee. TXU also maintained that the privilege period may be the same as the period used for the fee calculation.[726] Nonetheless, TXU argued that it properly recognized this payment pattern in its lead-lag study. TXU argued Dallas failed to recognize that TXU expressly removed all prepayments from the CWC calculation as required by PUC's Rule, 16 TEX. ADMIN. CODE §25.231(c)(2)(B)(iii)(IV)(a).[727] Accordingly, TXU Gas held that Dallas's proposal was not proper or appropriate.

Dallas's Position

Dallas argued that the question relating to the calculation of franchise fee payments is whether the payment

[720] Dallas Exhibit 1 at 106.
[721] TXU Exhibit 34 at 11.
[722] TXU Exhibit 34, attachment ALW-R-D at 89.
[723] TXU Exhibit 34, attachment ALW-R-D at 89.
[724] Dallas Exhibit 1 at 107.
[725] TXU Exhibit 34 at 5.
[726] TXU Exhibit 34 at 5.
[727] TXU Exhibit 34 at 5.

is a payment dictated by the words of the current franchise. Dallas argued that a franchise agreement which states that a payment on or before the 15th of February for "the preceding calendar quarter" means exactly that, i.e., not something else that is not in the current franchise agreement.[728] Dallas used the example of the franchise agreement between TXU and the City of Fort Worth to illustrate that franchise fee payments are wholly contained within the period specified under the franchise agreements. Dallas argued that the payments are not prepayments in the current franchise and that its alternative calculation of lead days on the franchise taxes more accurately reflects TXU's actual franchise fee payment experience.[729]

Examiners' Recommendation

The record evidence showed that (106.617) expense lead days is reasonable. Dallas presented probative evidence that the City of Fort Worth franchise agreement is clear in its meaning. The current franchise agreement states:

> The franchise fee shall be paid on or before the fifteenth (15th) day of February, May, August, and November of each year for the preceding calendar quarter during the term of this franchise. Such payments shall be by the utility and accepted by the City as full payment for the utility's privilege of using and occupying the streets, alleys and public thoroughfares within the city and of other fees connected with that use. . .
> (Amendment No 1. to City of Ft. Worth Ordinance No. 10692 TXU Gas Franchise.)[730]

Using the language of this franchise agreement, TXU's calculations providing net lead days incorporated the supposition of a prepayment,[731] which artificially shortened the overall applied lead days to this calculation. Using Dallas's corrections based on the franchise agreements of twelve cities resulted in a reasonable revision to this calculation. TXU failed to present probative evidence that its proposed calculation of expense lead days for franchise fees is representative of its actual experience and reasonable. Therefore, the Examiners recommend that the (106.617) lead day calculation be approved by the Commission.

k. Income Tax Payment Patterns

TXU proposed a (39.500) expense-lead-day level for federal income taxes (FIT) based on annual quarterly payments.[732] ACC argued that TXU's payment of FIT is hypothetical and therefore should be excluded from consideration in cash working capital.[733] The Examiners recommend that TXU's lead-lag study calculations for FIT be adopted.

TXU's Position

TXU argued that it accurately reflected expected income tax payment patterns in the lead-lag studies. TXU explained that it followed the Final Order in GUD 9145 as guidance for the FIT provisions in its lead-lag

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728 Dallas Initial Brief at 26 (Mar. 8, 2004).
729 Dallas Exhibit 1 at 107.
730 TXU Exhibit 34 attachment ALW-R-1 at 6.
731 TXU Exhibit 34 attachment ALW-R-2 at 90-106.
732 TXU Exhibit 34 attachment ALW-R-2 at 83 and 176.
733 ACC Exhibit 2 at 31.

studies.[734] TXU also used the requirements of the IRS to establish the due dates utilized in the studies.[735] These requirements provided that for corporations with a December 31 fiscal year, equal installments (25 percent each) are due on April 15, June 15, September 15, and December 15.TXU accurately reflected these payment dates in its CWC request.

ACC's Position
ACC argued that TXU Gas did not used actual income tax payments to calculate the lag in payment of income taxes.[736] As a result, the calculation is erroneous and contrary to established Commission precedent established in GUD 8976.[737] ACC relied on GUD 8976 to support its position that hypothetical tax payments should not be used. ACC argued TXU has not paid income taxes for the past several years; therefore, the only payment lag that could be used is a hypothetical lag.[738] ACC also argued that TXU does not make equal tax payments every quarter for income taxes; TXU's assertion that it makes equal tax payments for cash working capital purposes is wrong.

Examiners' Recommendation
The evidence shows TXU presented a reasonable calculation for FIT in the Distribution and Pipeline lead-lag studies.

The Examiners recommend that the lead days proposed by the utility and the provision for FIT in the Distribution and Pipeline lead-lag studies be approved by the Commission. ACC did not provide probative evidence to demonstrate that the expense lead calculation by TXU was unreasonable. ACC's argument that TXU's tax payments are hypothetical is based on the fact that TXU has received tax refunds and therefore does not pay taxes.[739] The Examiners find that the receipt of refunds means that TXU is refunded from payments that it made; therefore, the assertion that TXU's tax payments are hypothetical is not established.

l. Average Daily Bank Balances and Working Cash Funds

TXU's Position
TXU stated that average daily bank balances and working cash funds represent funds that TXU must maintain to meet the day-to-day cash needs of TXU Gas Distribution and Pipeline entities.[740] TXU's testimony noted that PUC Rule 25.231 provides:

> For electric utilities the balance of cash and working funds included in the *working cash allowance calculation shall consist of the average daily bank balance* of all non-interest bearing demand deposits and working cash funds. (Emphasis added.)
> (16 TEX. ADMIN. CODE §25.231(c)(2)(B)(iii)(IV)(e)(2003)).

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[734] TXU Exhibit 34 at 21.
[735] TXU Exhibit 34 at 21.
[736] TXU Exhibit 34 at 21.
[737] ACC Exhibit 2 at 31.
[738] ACC Exhibit 2 at 31.
[739] ACC Exhibit 2 at 31.
[740] ACC Exhibit 2 at 31.

TXU argued that PUC Rule 25.231 specifically required the inclusion of average daily bank balances in the CWC calculation.[741] TXU also argued that the funds included in Bank Balances and Working Funds have not been provided by the ratepayer, primarily because customers do not pre-pay their bills.[742] TXU explained that such funds are actually supplied by vendors, not customers.[743]

TXU noted that the PUC previously considered and rejected arguments similar to those asserted by ACC and Dallas. TXU argued that the record evidence, PUC Rule 25.231, and PUC precedent are clear that Average Daily Bank Balances should be included in the calculation of working capital.[744] TXU argued that the intervening parties' proposals regarding Average Bank Balances must be rejected.

TXU noted that ACC argued that Working Funds should be excluded from CWC, but PUC Rule 25.231 required the inclusion of Working Funds.[745]

ACC and Dallas's Position

ACC argued that TXU's practice of including bank balances and working funds in the calculation of cash working capital is contrary to established Railroad Commission precedent.[746] ACC stated that these are funds that ratepayers have provided, and it is inappropriate that the ratepayers should be required to compensate the shareholders for interest on funds that the shareholders did not provide.[747] ACC noted that the Commission established in GUD 9145, Finding of Fact No. 75, that if TXU's shareholders are not supplying the working cash, then the shareholders are not entitled to a return on that working cash; the working cash should not be included in the calculation of TXU's cash working capital needs.[748]

Dallas echoed ACC's contention that the inclusion of an amount for average daily bank balances, when the cash working capital is provided by ratepayers, double the charges to customers for the same expense. The denial of an amount for average daily bank balances is well established in prior cases before this Commission including GUD 9145. Dallas argued that TXU's response on this issue is a reference to the PUC Rule, not Docket 9145. Consistent with the Railroad Commission's prior precedent, Dallas urged that average bank balances should be removed from working capital.[749]

Examiners' Recommendation

TXU did not provide probative evidence showing that ratepayers should provide a return on funds that shareholders did not supply.

TXU request for a cash allowance for average daily bank balances and working funds is not reasonable. The Examiners recommend the Commission disallow TXU's proposal. The Commission rejected similar requests in GUD 8878, GUD 8976, and GUD 9145. TXU failed to provide probative evidence showing

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741 TXU Exhibit 21, attachment ALW-2 at 7.
742 TXU Exhibit 34 at 22.
743 Tr. Vol. 11 at 96-97 and 101-102.
744 Tr. Vol. 11 at 96-97 and 101-102.
745 TXU Exhibit 34 at 31.
746 TXU Exhibit 35 at 24.
747 ACC Exhibit 2 at 32.
748 ACC Exhibit 2 at 32.
749 Tr. Vol. 11 at 5095 and 102.

that Commission precedent should be ignored. While an allowance for average daily bank balances is provided under the provisions of PUC Rule 25.231 and may be permissible in a general allowance for cash working capital, this allowance applies to instances where average daily bank balances are provided by investor-supplied funds.[750] TXU did not establish that its average daily bank balances and working funds are investor-supplied. The evidence shows that ratepayers should not be required to compensate shareholders for return on funds they did not provide. The Examiners find that a substantial negative cash working capital implies that the bank balances are provided through funds made available by ratepayers.[751] The Examiners recommend exclusion of average daily bank balances and working funds from the calculation of Distribution CWC and Pipeline CWC.

m. Errors and Lead-Lag Study Reliability

In consideration of the preceding issues for cash working capital, the over-arching issue is whether the lead-lag study provided by TXU for Distribution and Pipeline operations provides a reasonable basis for arriving at an equitable level for a cash working capital allowance. TXU argued that the lead-lag studies for Distribution and Pipeline are reasonable and do not contain significant errors in either amount or effect.[752] ACC argued that TXU's lead-lag studies are flawed to the extent of being unreliable and therefore requested cash working capital request as determined by the lead-lag studies should be set aside in favor of an allowance equal to negative one-eighth of O&M expenses as provided under PUC Rule 25.231.[753]

TXU's Position

TXU argued that the lead-lag studies for Distribution and Pipeline result in reasonable levels of cash working capital and are not flawed, as alleged by the Intervenors.[754] TXU noted that a significant amount of time at the hearing was spent discussing clerical and input errors identified during the discovery process, but a relatively small number of errors was identified in the two lead-lag studies.[755] TXU maintained that in the tens of thousands of inputs in the two lead-lag studies, there were only 97 errors identified, and explained that in order to properly comprehend the insignificance of the 97 errors, it is important to understand the magnitude of the two lead-lag studies performed by TXU. During the hearing, TXU stated that over 4,000 pages of workpapers were created in preparation of the studies, with almost every page effectively covered with numbers and/or calculations. Out of all 4,000 plus workpapers, TXU stated that only 18 included errors. Accordingly, TXU concluded that over 3,980 workpapers included no errors. Given the volume of numbers included in the studies, TXU argued that it is not significant that 97 errors were identified.[756]

TXU noted that in good faith, it corrected every true error that was identified,[757] and argued that disagreements as to appropriate methodologies do not constitute "errors." TXU refused to make some

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[750] Dallas Exhibit 1 at 108.
[751] 16 TEX. ADMIN. CODE §25.231(c)(2)(B)(iii).
[752] GUD 9145-9148 at 37.
[753] TXU Exhibit 34 at 3; TXU Exhibit 34 at 6.
[754] ACC Exhibit 2 at 8.
[755] TXU Exhibit 34 at 3.
[756] TXU Initial Brief at 24 (Mar. 8, 2004).
[757] TXU Initial Brief at 24-25 (Mar. 8, 2004).

changes requested by the intervening parties.[758] TXU also argued that the PUC and the Commission have clearly established that changes to lead-lag studies, after they are filed, are allowed.[759]

TXU stated that the PUC contemplated that some level of errors is acceptable and even expected; otherwise there would be no need for a comparison of the number of errors with the "sample of the informational inputs against the statistically-predicted number of errors."[760] In addition, TXU maintained that 97 errors out of literally tens of thousands of inputs in the CWC calculation cannot be considered a high number of errors. Even if 97 errors were considered to be high, intervening parties provided no record evidence of "testing of a sample of the informational inputs against the statistically-predicted number of errors" specifically contemplated in the PUC's Preamble to its rule.[761] Thus, TXU concluded there is no evidence that the number of errors reaches the level contemplated by the PUC to be necessary to find the study "flawed."

TXU also observed that both the PUC and the Commission have allowed modifications to lead-lag studies significantly greater than those in this proceeding without finding that the study was flawed. In GUD 9145, intervening parties alleged that TXU's study was flawed. However, the Commission allowed modifications that were significantly greater than those that have occurred in this proceeding.[762]

ACC's Position

ACC stipulated that a reasonable allowance for cash working capital is generally included as an expense item in calculating a utility's invested capital. It represents the average amount of capital provided by investors to bridge the gap between the time expenditures are made to provide service and the time collections are received for those services. ACC described that a properly conducted lead-lag study is used to accurately measure the amount of cash investors must provide to support utility operations on a cash-flow basis.[763]

ACC argued that in this proceeding, TXU's lead-lag studies for Distribution and Pipeline are so flawed and so full of errors that they are unreliable and should be disregarded. ACC alleged TXU made a large number of mistakes in both its compilation of data and in its application of the proper methodology to the data, which were uncovered by the intervening parties through the discovery process. ACC also argued that although TXU made a number of corrections to its studies, many of these changes came at the last moment (when the sponsoring witness was on the stand),[764] or were incomplete.

It is ACC's position that in the absence of a reliable lead-lag study, TXU's cash working capital should be calculated using negative one-eighth of allowed operation and maintenance expense, including gas cost.[765] ACC recommends that the Commission find the lead-lag studies to be unreliable because TXU's study is rife with errors that rise above the level of methodological differences; failure to use weighted

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[758] TXU Exhibit 34 at 10.
[759] TXU Exhibit 34 at 10.
[760] TXU Exhibit 34 at 8.
[761] TXU Exhibit 34 at 11.
[762] TXU Exhibit 34 at 11.
[763] TXU Exhibit 34 at 11.
[764] ACC Exhibit 2 at 12.
[765] Tr. Vol. 5 at 18-63.

dollar days for revenue lag in the Distribution study; use of non-cash items in calculation of weighted dollar days for revenue lag in the Pipeline study; inconsistent use of mid-point of service period and dollar weighted lag days for O&M expense lag calculation; failure to reflect actual tax payment patterns for income tax payments; and improper inclusion of bank balances and working funds.[766]

ACC agrees with TXU that PUC Rule 25.231 provides appropriate guidance for the Commission, and urged that the rule be consistently applied to TXU's filing.[767] Most importantly, the Commission should be guided by paragraph (V) of that rule, that provides as follows:

> (V) If cash working capital is required to be determined by the use of a lead-lag study under the previous subclause and either the electric utility does not file a lead-lag study *or the electric utility's lead-lag study is determined to be so flawed as to be unreliable,* in the absence of persuasive evidence that suggests a different amount of cash working capital, an amount of cash working capital equal to negative one-eighth of operations and maintenance expense including fuel and purchased power will be presumed to be the reasonable level of cash working capital.[768] (Emphasis added.)

ACC stated that the extent of trust one can put in TXU's lead-lag study is severely diminished and the study itself is unreliable. Therefore ACC argued that under the mandate of the PUC rule, a cash working capital amount of negative one-eighth O&M expense should be presumed reasonable.[769]

Examiners' Recommendation
The evidence shows that TXU's lead-lag studies should be relied upon for determining cash working capital allowances for Distribution and Pipeline.

TXU's lead-lag studies for Distribution and Pipeline provide a reasonable basis for estimating cash working capital. The Examiners recommend the lead lag studies, as modified, are an appropriate means of arriving at a CWC allowance. ACC argued that TXU's lead-lag studies submitted for Distribution and Pipeline are so flawed as to be unreliable and therefore that negative one-eight of O&M expenses be designated as the cash working capital allowance for Distribution and Pipeline. The evidence presented did not show that ACC established a statistical standard or other standard to demonstrate the significance of the flaws it alleged.

The evidence presented in this proceeding did not show that the errors in the lead-lag studies invalidate the overall result of the studies. A lead-lag study will not produce an estimate of cash working capital that is precisely correct; the purpose of the study should be to arrive at an amount that is reasonable and contains no obvious defects. To the extent that the Intervening parties demonstrated defects in the lead-lag studies, the Examiners recommended corrections. However, the Examiners find that individual defects do not nullify the overall framework of a lead-lag study that is reasonable and that was conducted in good faith.

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766 ACC Exhibit 2 at 34.
767 ACC Exhibit 2 at 14.
768 ACC Exhibit 2 AT 10.
769 16 TEX. ADMIN. CODE §25.231(c)(2)(B)(iii).

B. Adjustments to Invested Capital

1. *Customer Information System*

<u>Issue</u>
The Customer Information System (CIS) is also discussed in the Affiliate Transactions section of this proposal for decision TXU Gas leases the CIS system to TXU Energy. This section discusses whether an adjustment to invested capital relating to the CIS would be appropriate. TXU argued that it properly included its net plant investment in the CIS as part of TXU Gas - Distribution's invested capital. TXU argued that the CIS system is gas utility plant investment that is used and useful in providing service to TXU's Distribution customers. Intervening parties did not argue that the costs associated with CIS were imprudent; however, ACC proposed to remove $2,691,934 of costs related to the CIS system from TXU Gas - Distribution's general plant invested capital. TXU countered that ACC's proposal lacked support.

<u>TXU's Position</u>
TXU argued that the sole purpose of the CIS system is to maintain gas customer records and perform the billing processes required to render gas billings to TXU Gas - Distribution customers. The CIS system is properly recorded as TXU Gas - Distribution plant because TXU Gas owns the CIS system. TXU stated that the capitalized cost of the CIS system was comprised solely of the cost of the enhancements to the base CIS system that are necessary to allow TXU Gas - Distribution to use this billing and customer care software. TXU also testified that the sole purpose of the CIS system is to maintain gas customer records and perform the billing processes required to render gas billings to TXU Gas - Distribution customers. It is TXU's position that its reliance on the system makes it used and useful to the utility. TXU urged that ACC's comments about the utility's software costs are not persuasive evidence. TXU argued that no party offered evidence to demonstrate that the CIS system costs were unreasonable or imprudent. Like all gas utility plant investment that is used and useful in providing service to the gas utility's Distribution customers, TXU Gas properly included its net plant investment in the CIS system as part of TXU Gas - Distribution's rate.[770]

<u>ACC's Position</u>
ACC took the position that the CIS is not totally used and useful solely to Distribution. ACC recommended a reduction of net Distribution plant in the amount of $2,691,934. ACC agreed with TXU's position that TXU Gas owns the Customer Information System (CIS). ACC noted, however, that TXU failed to mention that the CIS is not used and useful only to TXU Gas because TXU Energy must use this CIS asset in order to perform its obligations to TXU Gas under the Service Level Agreement (SLA). ACC stated that the computer software was developed in 1998 and had been included as a general plant investment in all of TXU Gas' filings since that time. Now, the CIS software is being used by TXU Energy to perform its required services on TXU Gas' behalf, pursuant to the Service Level Agreement. Thus, the CIS is not used exclusively for TXU Gas operations. TXU Energy's customers are also receiving the benefits of this software. But for the use by TXU Energy of the CIS asset, TXU Energy would not be able to meet its obligations under the SLA. ACC argued that the total cost of this plant should not be included in Distribution rate base, in accordance with TUC §104.051. ACC reduced the amount in the same

[770] TXU Exhibit 27 at 14; TXU Exhibit 30 at 3; ACC Initial Brief at 20-21 (Mar. 8 2004); TXU Reply Brief at 38 (Mar. 17, 2004).

percentage as the number of customer service representatives (CSRs) attributable to TXU Gas' operations to conclude that Distribution general plant should be reduced by $2,691,934. Because of the use by TXU Energy and the obvious usefulness of the CIS to TXU Energy, it is inappropriate to include all of the CIS costs in Distribution net general plant. Therefore, ACC argued that its proposed adjustment in the amount of ($2,691,934) should be made to net Distribution general plant.[771]

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ACC argued that TXU included the CIS in invested capital because it is on the gas utility's books, but that TXU has not determined whether the CIS is appropriately included for rate making purposes. ACC argued that TXU guessed that the CIS is used and useful to the utility, because it made no investigation as to whether any other entity is also using this asset. ACC argued that TXU did not take into account whether the asset was used and useful to other TXU entities when including it in rate base, and did not properly account for the asset that is shared by several entities. Even though TXU did not include the revenues received from TXU Energy under the Service Level Agreement in adjusted revenues, it has not made any adjustments to investment to reflect the fact that this asset is no longer used and useful 100 percent to gas customers.[772]

ACC concluded that its calculation is made on the basis of employee counts provided by TXU. ACC also noted that TXU's software investment costs are rising. ACC argued that the magnitude of these costs and the laissez-faire attitude of TXU regarding the used and useful standard should increase the Commission's scrutiny.[773]

Examiners' Recommendation
The evidence shows that the purpose of the CIS system is to maintain gas customer records and perform the billing processes required to render gas billings to TXU Gas - Distribution customers. The evidence also shows that the CIS system is used and useful to TXU Gas. The capitalized cost of the CIS system comprises of the cost of the enhancements to the base CIS system that are necessary to allow Distribution to use this billing and customer care software. Because TXU Gas must rely on the system for its billing, the CIS is used and useful to the utility. The evidence does not show that TXU's inclusion of CIS in invested capital violates the requirements of TUC §104.053. The Examiners recommend no adjustment to invested capital relating to the CIS. In TXU's initial filing, TXU had inappropriately double-counted this item. The Examiners note that the error has already been corrected in TXU Exhibit 61.

2. Accumulated Deprecation

Issues relating to Accumulated Depreciation begin on page 123 of this Proposal for Decision. The Examiners recommendation can be found on page 126. No additional discussion is necessary. The accumulated depreciation reserve calculation is dependant upon the Commission's decisions in this rate making proceeding.

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[771] ACC Exhibit 3 at 9-10; ACC Initial Brief at 38 (Mar. 8, 2004); ACC Final Brief at 18.
[772] ACC Exhibit 3 at 9-10; ACC Initial Brief at 38 (Mar. 8, 2004); ACC Final Brief at 18.
[773] ACC Final Brief at 18.

3. *Adjustments to Invested Capital*

<u>TXU's Position</u>

In this rate making proceeding, TXU Gas did not request a return on the adjusted value of invested capital as provided for in TUC §104.053. Instead, TXU requested a return on the net original cost of property, plant, and equipment that is being considered in this case. TXU stated that the Commission is therefore not required to make a determination of adjusted value rate base.[774]

TXU recalled no intervening party challenging its use of net original cost of property, plant, and equipment to value rate base in this docket. However, TXU noted that ACC reported that TXU had improperly recovered a return of approximately $36 million on adjusted value rate base between 1980 and 1995 and that this money should be returned or credited to TXU Gas' customers. ACC also argued that municipalities approved this return on adjusted value rate base due to utility representations and the belief that these dollars would be used to "cover the rising costs of replacing plant."[775] ACC's position lacks support and must be rejected.

First, TUC §104.053 expressly authorizes rates to be established using the adjusted value of rate base. Second, the evidence is uncontroverted that TXU received only the return authorized by either the Commission or the governing municipalities in which it provides services.[776] TXU noted that ACC did not challenge this position; rather, ACC speculated that the Commission would not have authorized such revenues if the municipally-approved rates had been appealed to the Commission for review. ACC's opinion on this matter is irrelevant. The municipalities in which TXU Gas provides service have exclusive original jurisdiction over TXU's Distribution rates under TUC §103.001. Thus, unless appealed, the municipalities have sole, and final authority to establish TXU's return. TXU observed that the municipalities served by the utility approved the recovery on and of certain amounts as part of the utility's invested capital. TXU argued that it is also undisputed that the utility has not received more than the return authorized by those governing municipalities.[777]

ACC's proposal attempts to modify prior rate orders constitutes retroactive ratemaking in violation of Texas law and therefore should be rejected.[778] TXU argued that the rule against retroactive ratemaking prohibits a regulatory authority from making a retrospective inquiry to determine whether a prior rate was reasonable and from imposing a surcharge when rates are too low or a refund when rates are too high.[779] ACC's proposed refund of authorized return dollars falls squarely within this prohibition. ACC's proposal is not, as it attempted to argue, comparable to the utility's establishment of regulatory assets for costs expensed in years outside the test year.[780] TXU Gas' return on the adjusted value rate base was approved by municipalities having original jurisdiction over the utility's rates and cannot be adjusted after the fact, contrary to ACC's assertion.[781] TXU argued that ACC's advocacy that the revenues recovered as

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[774] TXU Exhibit 14 at 8; TXU Initial Brief at 38-39 (Mar. 8, 2004); TXU Reply Brief at 39-40.

[775] ACC Initial Brief at 35 (Mar. 8, 2004).

[776] TXU Exhibit 27 at 13; TXU Initial Brief at 39 (Mar. 8, 2004).

[777] TXU Exhibit 27 at 13; TXU Initial Brief at 39 (Mar. 8, 2004); TXU Reply Brief at 38-39 (Mar. 17, 2004).

[778] *State v. PUC*, 883 S.W.2d 190, 199 (Tex. 1994).

[779] *State v. PUC*, 883 S.W.2d 190, 199 (Tex. 1994).

[780] ACC Initial Brief at 35.

[781] *Railroad Comm'n of Texas v. Moran Utilities Co.*, 728 S.W.2d 764, 768 (Tex. 1987).

authorized return be credited to ratepayers in the form of a negative regulatory asset, an adjustment to TXU's depreciation rates, or as a reduction to TXU's net salvage depreciation expense violates the legal principle of retroactive rate making.[782]

TXU also disagreed with ACC's recommendation to tie the proposed net salvage value with the historical return earned on adjusted value invested capital. ACC proposed the Commission should, ten years after the fact, reduce TXU's removal costs to reflect return dollars that were presumably earned on the utility's adjusted value invested capital. TXU advocated establishing net salvage value based on the historical experience of the utility rather than being derived from an artificial imputation that fails to reflect the utility's actual costs. TXU noted that ACC offered no support for its contention that return on adjusted value of invested capital was used as "a hedge against inflation."[783] ACC's reference to the inflation rates of the 1970s is also irrelevant given the time period (1980-1995) on which ACC based its proposed adjustment.[784]

TXU countered ACC's assertion that the utility "double recovered." The recovery of investment dollars occurs through the depreciation expense allowed in rates. Adjusted value rate base does not affect the recovery of this expense because depreciation expense is calculated on the original cost of the investment. Rather, inclusion of an adjusted value rate base factor affects only the calculation of the return earned on the investment. TXU stated that it receives only the return of its original investment regardless of whether an adjusted value rate base factor is included as part of the ratemaking calculation. TXU concluded that there is therefore no "double recovery" as ACC suggested.[785]

ACC's Position

ACC stated that TXU has inappropriately received additional funds related to adjusted value of invested capital. Prior to and throughout the 1980s and most of the 1990s, TXU inappropriately requested and received additional ratepayers' dollars; since 1980, the amount is estimated to be more than $36 million. These dollars were related to the utility's representation to local regulators that the law allowed for a return on the adjusted value rate base, and such return was in excess of any return shown to be reasonable based on the original cost rate base. [786]

From the 1970s until 1996, TXU represented to regulators that the incremental return applied to the adjusted value increment of invested capital (i.e., the difference between invested capital and adjusted value rate base) was required by law. ACC reported that in testimony in GUD 4153, after explaining his calculation of the incremental return applied to the adjusted value increment of rate base, Lone Star Gas witness Mr. Florence represented that Section 41(1) of the Public Utility Regulatory Act stated that "[u]ility rates shall be based upon the adjusted value of property. . .". Mr. Florence further testified that it was "necessary to calculate an incremental return on the adjusted value increment . . . I have applied a 1.0 percent rate of return to the adjusted value increment."[787] ACC stated that TXU did not contest this representation that the utility continued to request and receive the additional one percent return on the

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782 TXU Exhibit 27 at 13; TXU Initial Brief at 39 (Mar. 8, 2004); TXU Reply Brief at 38-39 (Mar. 17, 2004).

783 ACC Initial Brief at 33; TXU Reply Brief at 38-40 (Mar. 17, 2004).

784 TXU Initial Brief at 39 (Mar. 8, 2004); TXU Reply Brief at 38-40 (Mar. 17, 2004).

785 TXU Exhibit 27 at 13; TXU Initial Brief at 39 (Mar. 8, 2004);TXU Reply Brief at 38-409 (Mar. 17, 2004).

786 ACC Exhibit 3 at 33; ACC Initial Brief at 33 (Mar. 8, 2004); ACC Reply Brief at 31-32.

787 ACC Exhibit 3, attachment CTC-11at 7-8; ACC Reply Brief at 31-32.

adjusted value increment long after the Commission and the Court of Appeals had ruled that additional return based on adjusted value was inappropriate.[788]

TXU argued that adjusted value invested capital does not affect the recovery of depreciation expense because depreciation expense is calculated based on the original cost of the investment.[789] ACC argued that TXU is wrong because the depreciation rates TXU seeks in this case include not only the original cost of the assets, but also huge costs of removal (through very large negative salvage values). ACC explained that the additional one percent return on the adjusted value increment was historically supplied by the utility's ratepayers, not its investors, and was used as a hedge against inflation, i.e., to cover the rising costs of replacing plant. Because TXU received these additional dollars on the adjusted value rate base increment, and because such dollars were a hedge against inflationary pressures, then including large negative salvage values-due in large part to inflation-in the depreciation rates would necessarily result in a double recovery of the removal dollars.[790]

However, because of the significant negative salvage value of the plant being forecasted by TXU in this proceeding, (i.e., negative 40 percent), ACC argued that it is unlikely that TXU used the additional return for its stated purpose. Therefore, this additional return provided by ratepayers in local distribution cases, but not sanctioned in cases at the Commission, amounted to additional income to TXU's shareholders, for which ratepayers have received no corresponding benefits. ACC reported that TXU agreed that these funds were included in rates,[791] although the utility argued that these funds were like any other return on investment. ACC argued that if TXU was already receiving a fair return through the return on original cost, then these funds were not, in fact, return, but rather just additional dollars received by the utility to be used for replacement costs of plant.[792]

ACC suggested several remedies that are available to the Commission to attempt to compensate the ratepayers for having contributed these additional dollars to the shareholders over the years:

(1) Set up a negative regulatory asset to be amortized over a set period of time;

(2) Adjust TXU's depreciation rates to recognize that ratepayers have already contributed significantly toward the replacement costs of the assets; and

(3) Reduce TXU's depreciation expense associated with negative net salvage values for Distribution to recognize that the utility has received additional revenues intended for capital replacements.[793]

ACC noted that the adjusted value increment funds were provided pursuant to Lone Star Gas' position that a filing based on an adjusted value rate base was required by law. Because the law considers the adjusted value rate base to be appropriate to "hedge" against inflation and the need for additional capital, the additional monies inappropriately supplied to TXU as a result could be considered as an offset to the increasing costs of removal for plant. ACC understood that TXU is not requesting the Commission

788 *Railroad Commission of Texas v. Lone Star Gas Co.*, 599 S.W.2d 659 (Tex. Civ. App.--Austin 1980, writ ref'd, n.r.e.); ACC Reply Brief at 32.

789 TXU initial Brief at 39; ACC Reply Brief at 32.

790 ACC Reply Brief at 32-33.

791 ACC Initial Brief at 34 (Mar. 8, 2004); Tr. Vol. 2 at 186.

792 ACC Exhibit 3 at 33-34; ACC Initial Brief at 34 (Mar. 8, 2004).

793 ACC Initial Brief at 34 (Mar. 8, 2004).

approve a return on adjusted value rate base -- only on its original cost. ACC argued that TXU could have presented its case on an adjusted value basis, indicating that the return on original cost is all that has been required, even in these earlier cases at the local distribution level.[794]

TXU argued that ACC's proposal would be retroactive ratemaking and therefore inappropriate because it takes into account circumstances that existed before the test year. ACC responded by noting that in this proceeding, TXU argued that it has appropriately set up its regulatory assets from costs that were expensed in years outside of the test year due to regulatory requirements. For example, TXU proposed to establish positive regulatory assets to recover other post employment benefits (OPEB) or other past expenses. ACC argued that its proposal regarding this past one-percent over recovery by TXU is not different that its proposal is consistent with TXU's logic, because the additional return component was also received outside of the test year as a result of TXU's representations to local regulators when it filed its rate cases between 1980 and 1996. Therefore, ACC urged, the same argument concerning regulatory assets could be made with respect to these ratepayers' dollars that were provided. The additional dollars received by TXU under the misrepresentation that the adjusted value return increment was required by law necessarily means that regulators were told that a regulatory requirement forced the collection. Therefore, classification as a "regulatory asset" would be appropriate.[795]

TXU stated that increased removal costs are one primary reason why it has included a negative 40 percent net salvage value; However, TXU agreed that the cost of removal includes labor and "a lot of other components."[796] TXU further agreed that inflation would be a component in the cost of removal trends, and in fact, the high inflation rate in the 1970s actually caused the current cost of removal to be so high.[797] TXU stated that the net salvage amounts are intended to reflect what has happened up to the present. ACC reported that this statement by TXU supports its recommendation because what has actually happened up to the present is that the current costs to remove plant that was in service (on which the utility earned an additional one percent return) includes the inflation from the time that plant was put into service.

ACC provided an example that in 1985 the cost of removal was $X. If plant was put into service in 1985 and was then replaced in 2002, the removal costs in 2002 are now $X plus inflation from 1985 to 2002. ACC noted that inflation would necessarily impact all costs associated with replacement of plant, including labor, material and supplies, and equipment usage. Therefore, ACC argued, TXU's admission that costs of removal reflect present conditions confirms that inflation is included in the costs of removal. ACC also argued that TXU's agreement that salvage values are set in depreciation rates to estimate the costs of removal (in the aggregate) going forward confirms that inflation is included in the costs of removal. Therefore, if TXU received the additional one percent for inflation, then there is no need to recognize that same inflation in increased negative salvage. ACC argued that to do so would provide TXU with a double recovery of these funds from ratepayers.[798]

ACC concluded its argument stating that even though ACC presented an estimate on the amount of adjusted value increment and has not been able to measure such amounts absolutely, TXU did not disagree

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[794] ACC Initial Brief at 34 (Mar. 8, 2004).

[795] ACC Initial Brief at 34-35 (Mar. 8, 2004); ACC Reply Brief at 32 (Mar. 17, 2004).

[796] Tr. Vol. 2 at 190.

[797] Tr. Vol. 2 at 188-199; ACC Initial Brief at 34 (Mar. 8, 2004).

[798] Tr. Vol. 2 at 194; ACC Initial Brief at 33-36 (Mar. 8, 2004).

with the calculation of the adjusted value increment or disagree with the fact that TXU used the adjusted value increment.[799]

Examiners Recommendation

The Examiners recommend that the Commission make no adjustment to invested capital. The evidence presented in this proceeding does not support the contention that TXU requested and received over $36 million from the 1970s until 1996 due to the utility's representation to local or municipal regulators that the law allowed for a one percent adjustment to the invested capital.

TXU's return on the adjusted value rate base was approved by municipalities that exercised original jurisdiction over the utility and the utility's rates. It would be retroactive ratemaking in this proceeding to make a determination that the return on equity approved by a municipality in a prior ratemaking was incorrectly set. It is reasonable in this proceeding for the Commission to set rates for the future and not the past.

The Examiners find that, as stated in *State v. PUC*, 883 S.W.2d 190, 199 (Tex. 1994), the rule against retroactive ratemaking prohibits the Commission from setting future rates to allow a utility to recoup past losses or to refund to consumers excess utility profits. The Supreme Court of Texas went further to explain that the rule prohibits a regulatory authority from making a retrospective inquiry to determine whether a prior rate was reasonable and imposing a surcharge when rates were too low or a refund when rates were too high.

The Examiners considered ACC's arguments whether TXU's current calculation of net salvage value is too high as a result of the way that TXU was compensated for presumed inflation in prior years. The Examiners did not find evidence to support ACC's recommended options.

VII. RATE OF RETURN

The Commission must establish a reasonable rate of return for TXU. In establishing a gas utility's rates, the regulatory authority shall establish the utility's overall revenues at an amount that will permit the utility a reasonable opportunity to earn a reasonable return on the utility's invested capital used and useful in providing service to the public in excess of its reasonable and necessary operating expenses.[800] The regulatory authority may not establish a rate that yields more than a fair return on the adjusted value of the invested capital used and useful in providing service to the public.[801]

A utility's return on its investment is a product of the rate base multiplied by a fair rate of return.[802] Thus, having established a rate base, the next task for the Commission is to determine a suitable rate of return.[803] The rate of return is the amount of money that a utility is allowed an opportunity to earn, over and above operating expenses, depreciation and taxes. As noted by the Austin Court of Appeals in *Railroad*

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799 Tr. Vol. 8 at 234.
800 TEX. UTIL. CODE ANN. §104.051 (Vernon 1998).
801 TEX. UTIL. CODE ANN. §104.052 (Vernon 1998).
802 *Railroad Commission of Texas v. Lone Star Gas Company,* 599 S.W.2d 659 (Tex. App. – Austin 1980).
803 *Railroad Commission of Texas v. Lone Star Gas Company,* 599 S.W.2d 659 (Tex. App. – Austin 1980).

Commission v. Lone Star Gas Co., to achieve the rate of return that the utility should be allowed to earn, the regulatory agency should consider the cost to the utility of its capital expressed as follows: (1) interest on long-term debt; (2) dividends on preferred stock; and (3) earnings on common stock.[804]

The first step in determining an appropriate rate of return for TXU is calculating its capital structure. Each of the elements of the capital structure of the utility is given a weighting based upon its contribution to the company's capital structure to arrive at a composite rate of return.[805]

TXU's Position

TXU has requested an overall rate of return of 8.75 percent. This rate of return proposal is based on capital structure ratios of 48.3 percent long-term debt, 1.9 percent preferred securities, and 49.8 percent common equity. TXU has proposed a cost of long-term debt of 6.57 percent and a cost of preferred securities of 5.51 percent.[806] TXU has proposed a return on common equity of 11.00 percent.[807] The following tables summarize TXU's proposals for this docket (which concerns both pipeline and distribution systems) and Commission approved values in the TXU dockets most recently litigated before the Commission: GUD No. 8976 (which concerned the pipeline system) and GUD No. 9145 (which concerned the Dallas distribution system).

Table 7.1 Capital Structure

Capital Structure	9400 - Proposed	GUD No. 8976 - RRC approved	GUD No. 9145 - RRC approved
Long-term debt	48.3%	47.3%	47.1%
Preferred securities	1.9%	1.9%	1.7%
Common equity	49.8%	50.8%	51.2%

Table 7.2 Cost of Capital

Capital Cost	9400 - Proposed	GUD No. 8976 - RRC approved	GUD No. 9145 - RRC approved
Long-term debt	6.57%	7.42%	7.34%
Preferred securities	5.51%	6.58%	5.54%
Common equity	11.0%	11.0%	12.1%

[804] *Railroad Commission of Texas v. Lone Star Gas Company,* 599 S.W.2d 659 (Tex. App. – Austin 1980).
[805] *Railroad Commission of Texas v. Lone Star Gas Company,* 599 S.W.2d 659 (Tex. App. – Austin 1980).
[806] TXU Exhibit 62 at 4, 8.
[807] TXU Exhibit 62 at 7-8.

Table 7.3 Rate of Return

Rate of Return	9400 - Proposed	GUD No. 8976 - RRC approved	GUD No. 9145 - RRC approved
	8.75%	9.223%	9.75%

TXU's rate of return proposal was presented by TXU witness Bruce H. Fairchild. Dr. Fairchild based the capital structure ratios for TXU on eleven publicly traded LDC's at fiscal year-end 2002.[808] Dr. Fairchild testified that his proposal for TXU's capital structure is based on an analysis of publicly traded LDC's because the capital structures of TXU Gas and TXU are not well-suited to calculate the overall rate of return, and that this method is consistent with economic and legal principles underlying a fair rate of return, appropriately reflects business risk, cost of equity estimates are based directly on that for comparable utilities, and follows previous Commission decisions.[809]

Dr. Fairchild testified that the 6.57% and 5.51% average costs of debt and preferred stock are the average costs of debt and preferred stock at the most recent fiscal year-end for each of the eleven LDC's he analyzed.[810] The proposed rate of return on common equity was determined by Dr. Fairchild by utilizing the discounted cash flow method (DCF) and the risk premium method to establish a current cost of equity range for the group of LDC's.[811] Dr. Fairchild, who updated his initial analysis with more current data, testified on rebuttal that the updated DCF and risk premium analyses point to a current cost of equity range for the group of LDC's of between 10 and 11 percent.[812] Dr. Fairchild testified that TXU should be authorized a rate of return on common equity of 11 percent.[813] Dr. Fairchild justifies authorizing the upper end of the 10 to 11 percent equity range in order "to recognize the greater risk associated with TXU Gas being an integrated gas company versus having distribution-only operations."[814]

Allied Coalition of Cities' Position

ACC objects to TXU's proposed capital structure, cost of equity, cost of preferred securities, and cost of long-term debt.[815] ACC witness Steven Hill testified that the equity cost of capital for TXU should be in the range of 9.25% to10% and recommends that TXU's cost of equity be set at 9.375%.[816] Mr. Hill performed a DCF analysis of a group of gas distribution companies which yielded a cost of equity capital of 10.1%[817] Mr. Hill also performed three additional equity cost studies to compare and corroborate his DCF study. Mr. performed a Capital Asset Pricing Model study(CAPM), a Modified Earnings-Price Ratio analysis (MEPR), and a Market-to-Book Ratio analysis (MTB).[818] Mr. Hill testified that the corroborative

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808 TXU Exhibit 62 at 4.
809 TXU Exhibit 22 at 6.
810 TXU Exhibit 62 at 4.
811 TXU Exhibit 22 at 57-60; TXU Exhibit 62 at 4-8.
812 TXU Exhibit 62 at 6.
813 TXU Exhibit 62 at 7.
814 TXU Exhibit 62 at 7.
815 ACC Initial Brief at 40-68.
816 ACC Exhibit 62 at 4, 34, 38.
817 ACC Exhibit 62 at 22-32.
818 ACC Exhibit 62 at 33.

studies indicate that his DCF study may have over estimated the cost of equity.[819] Mr. Hill testified that it would be reasonable to set the allowable cost of equity at the midpoint of the study's range with a 25 basis point discount for the reduced risk that Senate Bill No. 1271 affords TXU.[820] Senate Bill No. 1271 was enacted as TEX. UTIL. CODE ANN. §104.301 and allows the utility to incrementally increase rates on new investment without first filing a statement of intent.

Mr. Hill testified that TXU's capital structure should be 45% common equity, 4.69% preferred stock, 9.19% preferred securities, 31.75% long-term debt, and 9.38% short-term debt.[821] Mr. Hill testified that the cost rates for preferred stock, preferred securities, long-term debt, and short-term debt are 4.67%, 6.79%, 6.39%, and 3.50%, respectively.[822] Based on the testimony of Mr. Hill, ACC argues that a 7.42% rate of return that should be authorized for TXU in this docket.[823]

City of Dallas's Position
Dallas recommends an overall rate of return of 8.18%.[824] Daniel Lawton testified on behalf of Dallas that the appropriate capital structure for TXU is 51.0% long-term debt, 1.1% preferred stock, and 47.9% common equity.[825] Mr. Lawton testified that the appropriate costs for long-term debt, preferred stock, and common equity are 6.71%, 5.53%, and 9.80%, respectively.[826]

Mr. Lawton's testimony is that TXU's proposed cost of equity is not reasonable. Mr. Lawton recommends a 9.80% cost of equity based on a DCF analysis using the same proxy companies as TXU's witness, a two-stage growth model, and an average risk premium calculation. Mr. Lawton calculated costs of equity of 9.4%, 9.8% and 10.2% using DCF, two-stage growth model, and average risk premium, respectively. His recommendation is the midpoint of these results.[827]

Examiners' Recommendation
The Commission must approve a rate of return on TXU's rate base that is just and reasonable and which fairly compensates the utility for investments made in providing gas service. The Examiners' find that the weight of the evidence indicates that the method proposed by TXU's witness Fairchild to establish the applicant's rate of return is reasonable. The evidence establishes that TXU's proposed capital structure with weighted parameters for long-term debt, preferred securities, and common equity is reasonable.

TXU's witness recommended that the higher value in his cost of equity range of 10% to 11% be approved by the Commission. Dallas's witness recommended the midpoint cost of equity in the studies he conducted. ACC's witness recommended the midpoint cost of equity, less a 25 basis point discount to reflect lower risk as a result of TEX. UTIL. CODE ANN. §104.301, as ACC's proposed cost of equity for the utility. The Examiners do not agree with TXU that the company has established that its operations are

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[819] ACC Exhibit 62 at 34.
[820] ACC Exhibit 62 at 37-38.
[821] ACC Exhibit 62 at 21.
[822] ACC Exhibit 62 at 21.
[823] ACC Initial Brief at 40-68.
[824] City of Dallas Closing Argument at 31.
[825] Dallas Exhibit 2 at 25.
[826] Dallas Exhibit 2 at 25.
[827] Dallas Exhibit 2 at 11-25.

more risky than the proxy class and necessarily justify higher cost of equity. Further, the Examiners agree with the positions espoused by ACC and Dallas that the ability of TXU to recover streams of revenue from investment under § 104.301 would tend to lower the risk premium demanded by a hypothetical investor in the utility's securities. Therefore the Examiners recommend the Commission approve a cost of equity of 10% for purposes of establishing the company's weighted average cost of capital and allowable rate of return. The Examiners also find that the weight of the evidence establishes that TXU's cost of debt and cost of preferred securities are reasonable. The Examiners recommend that the Commission approve an overall 8.258% rate of return for TXU.

VIII. REVENUES AND EXPENSES

A utility's revenues and expenses are considered in a ratemaking proceeding because a utility's net income should be equal to the required monetary return on the utility's rate base. TUC §104.055 provides that net income is the total revenues of the gas utility from its provision of gas utility service, less all reasonable and necessary expenses related to that gas utility service. Only the payments that the Commission finds to be reasonable and necessary for the provision of gas utility service are approved as expense items. TUC §104.055(b) requires the Commission to make specific findings of reasonableness and necessity of each item or class of items to be allowed as an expense. The Commission adopted 16 TEX. ADMIN. CODE §§7.501, 7.5252, 7.5525, 7.5414 for determination of revenues and expenses.

TUC §104.051 provides the standard for the Commission to establish revenues. The Commission sets rates to permit the utility a reasonable opportunity to earn a reasonable return on the utility's invested capital used and useful in providing service to the public in excess of its reasonable and necessary operating expenses.

A. Revenues

1. Revenues

TXU proposed several adjustments to the data used to determine its cost of service and revenue requirements. The issues before the Commission are whether the proposed adjustments are reasonable and necessary for the establishment of just and reasonable rates. Alternatively phrased, the Commission must decide whether the data adjustments proposed by the utility are sound rate-making procedures, give a more accurate portrayal of the utility's cost of service and revenue requirement, and lead to the establishment of just and reasonable rates. TXU's testimony and schedules regarding revenue are presented at TXU Exhibit 17 at 3-6 and TXU Exhibits 6-8 and 61 at Schedules F-1(D), F-1(P), WP/F-1(D), and WP/F-1(P).

2. Gain on Sale of Assets

<u>Issue</u>
In test year 2002, TXU Distribution sold the Carrollton Service Center land to CB/Title, Ltd. and Billingsley Realty Investors, Ltd. The sales totaled $2,466,146. The net book value was $1,037,533. The net gain was $1,428,613. Also in test year 2002, TXU Pipeline sold cushion gas to Richardson Energy Marketing and to TXU Energy Trading. The sales totaled $5,260,600. The net book value was

$1,484,808. The net gain was $3,775,792.[828] The issue regarding the gain on the sale of assets is whether shareholders and ratepayers should benefit from gains on the sales of the assets.

TXU's Position

TXU argued that the evidence shows it properly handled the gain on the sales of land. TXU disagreed with ATM's proposal to reduce Pipeline's invested capital by $3,775,792 for gains on the sale of cushion gas or Distribution's invested capital by $1,428,613 for gains on sales related to land.

TXU argued that in GUD Nos. 8664, 8976, and 9145, the Commission considered and rejected arguments that the gain on plant sales should be treated as an adjustment to invested capital.[829] TXU noted that the arguments in those dockets are the same arguments made in this proceeding. TXU argues that ATM ignored the Commission requirement that TXU adhere to the NARUC system of accounts.[830] NARUC requires TXU Gas to book gains or losses "below the line."[831] ATM's proposal would require TXU to disregard the Commission's rule mandating compliance with NARUC and instead treat gains on plant sales as an "above the line" item. ATM's proposal would reduce TXU Distribution's and TXU Pipeline's invested capital.

TXU argued that the evidentiary record shows land and cushion gas to be non-depreciable; therefore, TXU Gas' customers have not contributed a return to investors on their invested capital for these assets.[832] TXU explained that depreciation involves the recovery of investment from customers. Thus, it is through the recovery of depreciation expense that TXU Gas recovers from its customers the investment in utility assets. TXU Gas does not, however, recover depreciation expense on land or cushion gas and does not recover from its customers the investment in land or cushion gas. TXU asserted that this position went unchallenged in this proceeding.[833]

TXU also argued that there has been no evidence showing that the customers have borne any of the risk associated with the land or cushion gas. Before the allocation to TXU Gas' customers of any gain related to such a sale, such a showing would have been required.[834] In *Gulf States*, the Texas Supreme Court noted that an allocation of the gain from the sale of plant must be governed by the equitable principles that "benefits should follow burdens" and that "gain should follow risk of loss." TXU argued that in this proceeding, the risk of loss and the risk of inadequate return has been borne by investors. Because investors provided the financing for the assets that were sold, it is the investors that bore the risk of those assets becoming less valuable over time. TXU argued the *Gulf States* standard was not met and the record does not support a finding that any gain associated with the sale of land should benefit the ratepayers. TXU stated that TXU Gas' customers benefitted from the use of the land and cushion gas, that TXU Gas excluded these assets from its invested capital in this docket to reflect the sale of these assets prior to the test year, and ATM's proposed adjustment should be denied. TXU summarized that (1) TXU Gas

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[828] ATM Exhibit 1, attachment MLA-7.

[829] *See* GUD 8664, Second Order Nunc Pro Tunc, FOF No. 24 (November 25, 1997); GUD 8976, Final Order, FOF Nos. 102-106 (June 22, 2000); GUD 9145, Final Order, FOF Nos. 90-94 (November 20, 2000).

[830] 16 TEX. ADMIN. CODE §7.43.

[831] TXU Exhibit 27 at 31.

[832] TXU Exhibit 27 at 31.

[833] TXU Initial Brief at 50-51 (Mar. 8, 2004); TXU Reply Brief at 49-51 (Mar. 17, 204).

[834] *Public Util. Comm'n of Texas v. Gulf States Utilities Co.*, 809 S.W.2d 201 (Tex. 1991).

complied with NARUC and the Commission's rules that require land sales to be booked below the line; (2) there has been no showing that customers have borne any of the risk associated with the investment in the sold property, as required under the Texas Supreme Court's ruling in *Gulf States*; and (3) prior Commission Orders establish that invested capital should not be adjusted based on the sale of facilities.[835]

<u>*ATM's Position*</u>

ATM considered TXU's position that it should get to keep 100 percent of the gain on the sale of cushion gas and gains on the sale of land. ACC argued that, contrary to TXU's position, ratepayers have been paying expenses associated with these two assets and have been paying a return on invested capital (rate base) on both these items.

ATM argued that gains on the sales of assets are recurring events as certain utility property is no longer needed and the property is sold. Because ratepayers have paid for the cost of capital and expenses on this property while it was used to provide utility service, the ratepayers should also benefit from any gains when the property is sold. The Distribution assets were sold at 2.38 times net book value which is a 138 percent return on the investment. The Pipeline assets were sold at 3.74 times net book value which is a 274 percent return on investment. ATM argued that failure to recognize these gains for ratemaking purposes would result in windfall profits for TXU Gas.[836]

ATM recommended that the gain on the sale of these assets be amortized over three years and the unamortized balances be included as an invested capital deduction. ATM's proposed adjustments reduce Distribution invested capital by \$1,428,613 and amortization expense by \$476,204 (\$1,428,613 ÷ 3 years = \$476,204). In addition, ATM's proposed adjustments reduce Pipeline invested capital by \$3,775,792 and amortization expense by \$1,258,597 (\$3,775,792 ÷ 3 years = \$1,258,597).[837]

ATM acknowledged TXU's reference to *Public Utility Comm'n v. Gulf States* for the proposition that the "benefits should follow the burdens." ACC argued that TXU has benefitted from ratepayers paying a return on these assets and paying the expenses related to these two assets. As a matter of equity, ratepayers should not be shut out from at least receiving a portion of the gain. ACC noted that regulatory commissions often split the gain between shareholders and ratepayers on a 50/50 basis. ACC reported that in a Southern California Gas Company case, the gain on the sale of cushion gas was split on a 50/50 basis between shareholders and ratepayers[838] and in a recent New Jersey Board of Public Utilities Case, the Board approved a 50/50 split between shareholders/ratepayers on the gain from the sale of land by the utility.[839] ATM concluded that given the equities in this proceeding, it is grossly unfair for TXU to keep all the gain.[840]

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[835] TXU Initial Brief at 50-51 (Mar. 8, 2004); TXU Reply Brief at 49-51 (Mar. 17, 204).

[836] ATM Exhibit 1 at 46-48; ATM Exhibit, attachment MLA-7; ATM Initial Brief at 47-48; ATM Reply Brief at 14-15.

[837] ATM Exhibit 1 at 46-48; ATM Exhibit, attachment MLA-7; ATM Initial Brief at 47-48; ATM Reply Brief at 14-15.

[838] ATM Reply Brief at 14-15 (Mar. 17, 2004) citing *Decision, Re Southern California Gas Company*, 2001 WL 1160003, at 8 (Cal. PUC, June 28, 2001).

[839] ATM Reply Brief at 14-15 (Mar. 17, 2004) citing Order Adopting Initial Decision/Settlement, *Re Elizabethtown Water Company*, 2002 WL 1969372 (NJ Bd. Of Public Utilities, Jan. 23, 2002).

[840] ATM Exhibit 1 at 46-48; ATM Exhibit, attachment MLA-7; ATM Initial Brief at 47-48; ATM Reply Brief at 14-15.

Examiners' Recommendation

The Examiners recommend that ATM's proposed adjustment be allowed. As in GUD 9145, the Examiners in this proceeding rely upon the standard in the *Gulf States* case in which, the Texas Supreme Court held that gains should be allocated to that group (as between shareholders and ratepayers) that has "borne the financial burdens (e.g., depreciation, maintenance, taxes) and risks of the asset sold." The Court enumerated several other factors that may be considered: (1) whether the asset has been included in rate base over the years; (2) whether the asset is depreciable property; (3) the impact of the proposed allocation on the financial strength of the utility; (4) the reason for the asset's appreciation; (5) any advantages enjoyed by the shareholders because of the favored treatment accorded the asset; and (6) any extraordinary burdens borne by the ratepayers in connection with the asset.

The Examiners do not find that the record evidence contradicts TXU's position that it properly booked the gain or loss of asset sales. The record shows TXU booked the sales to the appropriate NARUC accounts. However, examination of the record must go further because there is a difference between a return *of* invested capital and a return *on* invested capital. The evidence shows that customers have contributed to these assets. Evidence at TXU Exhibit 61, Schedule E(P), Line 5 shows that cushion gas is included as an item in invested capital. Record evidence at Exhibit 61, Schedule C-1(D), Line 2 shows that land is an item also included as original cost of Distribution plant-in-service. When TXU sells an asset, it takes the item out of these accounts. TXU's treatment of its books to record gain or loss on the sale of an asset does not modify the inclusion of the assets in rates. Until the time that rates are set that do not include the items in those accounts, the ratepayer continues to pay amounts for those assets.

The evidence shows that the ratepayer has borne the financial burden; therefore, the Examiners find that the ratepayers should receive a benefit from the sale of these assets. The Examiners find that further support for this recommendation in TXU's own testimony. In GUDs 8664, 8976, and 9145, the Commission considered arguments that the gain on plant sales should be treated as an adjustment to invested capital. ATM Exhibit 1, attachment MLA-7 shows that TXU included cushion gas in 1999, 2000, and 2002 invested capital. Cushion gas was sold by TXU for a gain in 1999, 2000, and 2002. The Exhibit also shows that TXU previously included items like office buildings. Unlike GUD 9145, the Examiners in this proceeding have considered the sale of assets that occurred during the test year. The Examiners find that because customers payed for a return on these accounts, they have contributed to the assets and should therefore receive benefits from the sale of those assets.

Having considered all the evidence presented by the parties relating to the gains on the sales of assets, the Examiners find that ratepayers have borne the financial burdens and risks of the asset sold, that the assets have been included in invested capital prior to the sales, that TXU's financial integrity will not be at risk if it were to share the benefit of the sale of the sold asset, and that the shareholders would enjoy a windfall if the benefit were not shared with ratepayers. The evidence shows that the Distribution assets were sold at 2.38 times net book value, which is a 138 percent return on the investment; the Pipeline assets were sold at 3.74 times net book value, a 274 percent return on investment. The Examiners find that an adjustment to invested capital is reasonable.

The Examiners recommend the Commission reduce TXU's proposed Distribution invested capital by $952,409 ($1,428,613- $476,204) and reduce Distribution amortization expense by $476,204 ($1,428,613 ÷ 3 years = $476,204). The Examiners also recommend the Commission reduce TXU's proposed Pipeline invested capital by $2,517,195 ($3,775,792-$1,258,597) and reduce Pipeline amortization expense by

$1,258,597.[841]

3. Transfers of Assets between Pipeline and Distribution

The issue of transfers of assets between Pipeline and Distribution are discussed starting at page 140. The Examiners affirm their recommendation. No adjustment to revenue is needed for transfers of assets between Pipeline and Distribution.

4. Affiliate Transactions

Affiliate Transactions issues and the Examiners' recommendations are discussed starting at page 46.

5. Removal of Poyner and Riesel Environs Duplicated Revenue

ACC identified that TXU duplicated the revenues reported for the Poyner and Riesel Environs on WP/L-1/9(D).[842] Accordingly, TXU reduced the Distribution Residential and Commercial revenues in the amount of $10,394, including gas costs. [843]

Intervening Parties' Positions
No intervening party opposed the reduction in the Distribution Residential and Commercial revenues to account for the duplication of revenues reported for the Poyner and Riesel Environs.

Examiners' Recommendation
The Examiners recommend that the Distribution residential and commercial revenues be reduced in the amount of $10,394, including gas costs.

6. Temporary Disconnects

The issue of temporary disconnects is discussed in this Proposal for Decision in the Rate Design Miscellaneous Service Charges section, beginning at page 262.

7. Weather Normalization

TXU's Position
TXU has proposed weather normalization adjustments to the sales volumes of residential and commercial customers. Mr. Gary L. Goble, of Management Applications Consulting, Inc., testified on behalf of the Applicant regarding the proposed weather normalization adjustments.[844] Mr. Goble testified that abnormal weather conditions during a test year may result in overstated or understated gas volumes during that test

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[841] ATM Exhibit 1at 46-48; ATM Exhibit, attachment MLA-7; ATM Initial Brief at 47-48; ATM Reply Brief at 14-15.

[842] ACC Initial Brief at 79 (March 8, 2004); ACC Exhibit 7 at 33.

[843] Hearing Examiners' Exhibit 6, page 2, line 1.

[844] TXU Exhibits 24 and 39.

year and therefore it is necessary to adjust test year gas sales for weather.[845] Mr. Goble also testified that TXU proposes no weather normalization adjustment to transportation and industrial gas sales because these types of gas usage are non-weather sensitive and have little seasonal fluctuation.[846]

Mr. Goble testified that the weather normalization adjustment procedure for residential and commercial gas sales volumes involved the following: (a) identifying the weather sensitive portions of gas sales; (b) determining the Mcf per Heating Degree Day (HDD) portion of sales; (c) adjusting the weather sensitive portion of sales up or down; and (d) calculating the total weather adjusted Mcf sales volumes.[847] The weather normalization adjustment is based on use of HDD data reported by the National Oceanic and Atmospheric Administration (NOAA) for ten (10) weather stations that cover the geographic area where TXU provides gas service. Annual normal HDDs total 2,362 for the test year. The actual number of HDDs for the test year totaled 2,457. The weather normalization adjustment reduces annual gas sales by 2,393,043 Mcf for residential customers during the test year. Likewise, the weather normalization adjustment reduces annual gas sales by 958,900 Mcf for commercial customers during the test year.

Allied Coalition of Cities' Position

ACC's position is that TXU's weather normalization adjustments for residential and commercial gas sales should be disallowed.[848] ACC argues that TXU's weather normalization is not needed and that the calculation is not reasonable. ACC argues that TXU's weather normalization calculation is flawed for the following reasons: (1) the calculation inappropriately uses ten (10) weather stations for HDD data; (2) the adjustment is inappropriate at the total company level; (3) the calculation of the HDD normals is inconsistent with NOAA methodology; (4) test year HDDs are inappropriately included in the HDD normals; and (5) the month of June is inappropriately excluded from the base load.[849]

Association of TXU Municipalities' Position

ATM stated in its Initial Closing Brief that it supports ACC's proposals regarding adjustments to weather normalization.[850]

Examiners' Recommendation

The Examiners recommend that TXU's weather normalization adjustment for residential and commercial customers be adopted. TXU utilizes the weather normalization procedure that is discussed in the Natural Gas Rate Review Handbook.[851] Weather normalization adjustments for gas sales are necessary in order to account for the net effect of below average and above average heating degree days during a test year. By making such adjustments, gas sales during the test year will not be over or under-stated and ultimately distort the test-year cost of service of the utility. TXU's proposed weather normalization procedure is reasonable and will prevent the distortion of gas sales numbers during the test year. The weight of the evidence does not support the position advocated by ACC.

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845 TXU Exhibit 24 at 6.
846 TXU Exhibit 24 at 7.
847 TXU Exhibit 24 at 35-36 (GLG -3).
848 ACC Exhibit 3 at 20; ACC Initial Brief at 68-69.
849 ACC Exhibit 3 at 21-27; ACC Initial Brief at 68-75.
850 ATM Initial Brief at 49.
851 Natural Gas Rate Review Handbook pps. 33, 45-48, and 50-51.

8. Customer Growth Adjustment

TXU's Position

TXU proposed making adjustments to the number of residential and commercial customers. Mr. Gary L. Goble offered testimony regarding the Applicant's proposed adjustment methodology.[852] Mr. Goble testified that by "adjusting sales and customers to reflect changes in the number of customers occurring during the test year, costs and revenues related to changes in the number of customers are presented at a level that more accurately depicts the anticipated costs and revenues during the period in which rates will be in effect."[853] The adjustments were made to reflect the levels of customers for residential and commercial class customers for the test year.[854] TXU's customer adjustment is made to the number of customers, sales volumes, gas costs, and revenues.[855] The test year adjustments for the number of customers increases annual gas sales by 966,152 Mcf for residential customers during the test year. The adjustments for the number of customers increases annual gas sales by 439,657 Mcf for commercial customers during the test year.

Allied Coalition of Cities' Position

ACC's position is that TXU's customer growth adjustment should be disallowed.[856] ACC argues that TXU's customer growth adjustment is inappropriately calculated on a system-wide level. ACC argues that any customer growth adjustment should be performed on a jurisdiction by jurisdiction basis and be based on the average and year-end customer counts in each of the jurisdictions.[857]

Examiners' Recommendation

The Examiners recommend that TXU's customer growth adjustment for residential and commercial customers be adopted. TXU's proposed customer growth adjustment procedure is reasonable. TXU has proposed system-wide rates and the adjustment methodology TXU advocates is reasonable and appropriate under the circumstances. TXU's proposed customer growth adjustment is necessary to accurately reflect the numbers of customers receiving service at the end of the test year. The weight of the evidence does not support the position advocated by ACC.

9. Industrial, Transportation, and Pipeline Transportation Customers, Sales and Revenues

TXU's Position

TXU has proposed adjustments to industrial, transportation, and pipeline transportation customers, sales and revenues. Mr. Gary L. Goble testified on behalf of the Applicant regarding the proposed adjustments.[858] Mr. Goble testified that transportation customers served directly from the pipeline portion of the system were removed from the books and records of the distribution system so that the actual

[852] TXU Exhibits 24 and 39.
[853] TXU Exhibit 24 at 5.
[854] TXU Exhibit 24 at 5.
[855] TXU Exhibit 24 at 6.
[856] ACC Exhibit 3 at 28; ACC Initial Brief at 76.
[857] ACC Exhibit 3; ACC Initial Brief at 76.
[858] TXU Exhibits 24 and 39.

number of customers, Mcf, and revenues for the distribution portion would not be misstated.[859] Mr. Goble also testified that TXU proposes adjustments to recognize the effects of industrial and transportation customers changing service classes, customers leaving the distribution system, and industrial sales customers being reclassified as commercial customers.[860] TXU proposes adjusting industrial sales revenue to annualize revenue for each customer based on volume adjustments.[861] TXU also proposes adjusting industrial sales revenue to reflect gas cost.[862]

Allied Coalition of Cities' Position
ACC's position is that the transfer to pipeline of industrial distribution customers should be disallowed and customers and volumes should be moved back to distribution.[863] ACC argues that the transfers of customers and usage associated with plant transfers from TXU Gas-Distribution to TXU Gas-Pipeline occurring prior to the test year should be disallowed.[864]

Examiners' Recommendation
The Examiners recommend that TXU's proposed adjustments to industrial, transportation, and pipeline transportation customers, sales and revenues be adopted. TXU's proposed adjustment procedure is reasonable. TXU's adjustments will allow a more accurate depiction of customer usage, revenues and costs on TXU's system during the test year. The adjustments are necessary because they more accurately reflect customers' actual use of the system and known and measurable changes in customer status. The weight of the evidence does not support the position advocated by ACC.

B. Expenses

1. New Investment

From 1998 to 2002, the utility invested approximately $721 million dollars in the System, $107 million of which was invested in the test year. All of the costs associated with the new investment the utility made in the System, all of which is used and useful, are reasonable and necessary. TXU argued that there have been no challenges to the used and useful nature of the investment nor has there been a challenge to the level of expense associated with the initial investment made by the utility.[865] As discussed in this section and throughout the PFD, the intervening parties challenged TXU's proposed expenses for Poly 1 pipe replacement, plant relocation, CCNC, etc.

2. Lost and Unaccounted for Gas

The issue of lost and unaccounted for gas is addressed in the Gas Cost Recovery and Lost and Unaccounted for Gas section of this proposal for decision, beginning at page 232.

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[859] TXU Exhibit 24 at 8-9.
[860] TXU Exhibit 24 at 8-9.
[861] TXU Exhibit 24 at 8-9.
[862] TXU Exhibit 24 at 8-9.
[863] ACC Exhibit 3 at 20.
[864] ACC Exhibit 3 at 29.
[865] TXU Exhibit 13 at 3-7; TXU Initial Brief at 58.

3. *Transfer of Gathering Facilities*

The issue of transfers of assets between Pipeline and Distribution are discussed starting at page 140. The Examiners affirm their recommendation. No adjustment to expense is needed for transfers of facilities.

4. *PEP Adjustment*

The Performance Enhancement Plan (PEP) is one component of overall employee compensation, which also includes base pay, overtime pay, and holiday premiums. TXU proposed an upward adjustment from test year levels. ACC argued that these items are not known and measurable changes.

TXU's Position
TXU asserted that the proposed adjustments to test year amounts are reasonable and necessary and reflect expected costs for the period in which rates will be in effect.[866] TXU explained that it adjusted test year salary expense to reflect a compensation increase anticipated to reflect ongoing future salaries incurred by TXU Gas, the PEP adjustment.[867]

TXU argued that it could have eliminated parties' challenges to this expense adjustment by paying each employee a higher base salary. However, TXU attempted to promote productivity increases, provide higher levels of quality customer service, and promote safe and efficient operating activities through a salary plan (PEP) that rewards employee performance that is beneficial to both TXU and to its customers. TXU's programs encourage desired performance by making a portion of the employees' overall compensation contingent on the accomplishment of certain financial and operational goals. If standards are met, the employee receives the PEP component of his or her salary. If the goals are not accomplished, an employee would not receive the PEP component.[868] Accordingly, PEP is designed to encourage TXU employees to perform more efficiently and safely, and providing a higher quality of customer service. TXU should not be penalized for attempting to encourage better performance by its employees.

TXU addressed the arguments of ACC. ACC stated that the PEP adjustment is "at risk" and should be denied. TXU argued ACC misrepresented the level of "risk" associated with the PEP adjustment and recommended an adjustment that would wrongly penalize TXU Gas for attempting to achieve a higher quality of customer service and a more efficient, safer company. PEP is not a "bonus" or "profit sharing" compensation plan. Rather, it is a component of each employees' annual salary. TXU Gas total salaries are targeted to be paid at the median (i.e., 50th percentile) of the appropriate market salary range with opportunities for individual employees to increase their total compensation based on performance. Isolating and removing a portion of an employee's total compensation, as recommended by ACC, would understate TXU's payroll costs from those costs actually incurred, and would penalize the utility in its efforts to promote productivity increases, provide higher levels of quality customer service, and promote safe and efficient operating activities through a salary plan that rewards desired performance. This is especially true given that PEP has been paid out every single year since the program's inception and because PEP is specifically structured in a manner that provides any given employee an 80 percent or

[866] TXU 17 at 10; TXU Exhibits 6, 7, and 61, Schedules G-5(D) and G-5(P).
[867] TXU Exhibits 6A, 8, and 61, at WP/G-5.5(D) and WP/G-5.5(P).
[868] TXU s Exhibit 30 at 4-6.

greater opportunity to receive the PEP payout at "target" level. The goals of the program are just and beneficial to both TXU and its customers.[869] TXU argued that ACC's recommendation should be denied and the utility's adjustment should be approved.

ACC's Position

ACC argued that TXU's proposed adjustments for its Performance Enhancement Plan (PEP) should not be approved because the adjustment proposed by TXU is not reasonable and necessary, and should not be approved as a known and measurable adjustment. ACC recommended adjusting Account 920 (A&G Salaries) to remove $1,030,834 from Distribution and $465,438 from Pipeline for Performance Enhancement Plan (PEP) compensation increases.[870] ACC's adjustment did not eliminate entirely the PEP compensation. TXU test year expenses included $2,296,166 for Distribution and $774,366 for Pipeline for PEP payments and those amounts are the only known and measurable levels of PEP expense that should be allowed.[871]

ACC addressed TXU's criticism of ACC's use of the term "at risk" to describe the PEP adjustment. ACC noted that TXU described the PEP program as "at risk" at least three times in response to ACC during discovery. TXU testified that PEP compensation has been paid every single year since 1998, but the amount paid is based on a range depending on performance. TXU also testified that it did not know what the performance levels would be in the future. As such, TXU's proposed adjustments are not known and measurable and should not be approved.[872]

ACC argued that TXU is again proposing that costs included in rates should be increased over test year levels at a time when TXU stated that its costs are too high and is in the process of implementing company-wide cost reduction programs. ACC noted that one of the guiding principles articulated in the early planning phase of the WINS program was that the cost reduction initiatives were about "creating value for TXU, not what is best for a functional group but what is best for the enterprise."[873] ACC argued that what creates value for TXU's shareholders in terms of cost reductions should also be shared with TXU's captive ratepayers. Therefore, ACC recommended the Commission disapprove TXU's proposal to add dollars to the PEP program account over and above test year amounts.[874]

Examiners' Recommendation

TXU's response to ACC RFI 1-151[875] included a statement in section (a) that TXU's proposed PEP upward adjustment beyond test year levels assumed performance at an expected level of attainment. TXU then attached its evidence of compensation adjustment for Distribution and Pipeline. For Distribution, TXU reported that it recorded $2,296,166 of compensation adjustment in test year 2002 but was requesting a

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[869] TXU Exhibit 31 at 4-6.

[870] TXU Exhibit 4 at 26a; TXU Exhibit 61, WP/G-5.5(D), line 10; TXU Exhibit 61, WP/G-5.5(P), line 10.

[871] ACC Exhibit 2 at 27a-30; ACC Exhibit 2, Appendix C (TXU Response to Dallas RFI 6-11); ACC Exhibit 2, Appendix C (TXU Response to Dallas RFI 8-6); Tr. Vol. 9 at 102 - 103. ACC Initial Brief at 128-130.

[872] ACC Exhibit 2 at 27a-30; ACC Exhibit 2, Appendix C (TXU Response to Dallas RFI 6-11); ACC Exhibit 2, Appendix C (TXU Response to Dallas RFI 8-6); Tr. Vol. 9 at 102 - 103. ACC Initial Brief at 128-130.

[873] ACC Exhibit 29.

[874] ACC Reply Brief at 68-69.

[875] ACC Exhibit 4, Appendix C (TXU's response to ACC's RFI 1-151).

$1,030,834 increase to achieve a 2003 target amount of $3,327,000.[876] For Pipeline, TXU reported that it recorded $2,774,366 of compensation adjustment in test year 2002 but was requesting a $465,438 increase to achieve a 2003 target amount of $1,239,804. The Examiners find that TXU did not provide probative, meaningful evidence to show that the upward adjustments were both reasonable and necessary. The evidence shows that the upward adjustments were requested by TXU based on assumption and expected level of performance by TXU employees. The Examiners find that the requested adjustment is speculative and is not known and measurable. Therefore, it is reasonable for the Commission to approve the test year levels of $2,296,166 for Distribution and $2,774,366 for Pipeline and to disallow any adjustments.

5. DICP Adjustment

The Deferred Incentive Compensation Plan (DICP) is a special stock-based compensation program for senior management officials of TXU Corporation. The stock in the DICP is purchased by a trustee using a deferred percentage of the salaries of certain qualifying TXU system participants. The eligible participants are elected corporate officers of TXU Corp. and its participating subsidiaries with the title of Vice President or above. The participants may defer up to 15 percent of their base salary. TXU makes a matching award equal to 150 percent of the participant's deferred salary. TXU reported that the participants bear all of the risk, and receive all of the reward, of fluctuations in the value of the TXU Corp. stock held in the DICP for their benefit. In this sense, it is similar to a 401(k) or other account that is invested in equity stocks. The DICP fluctuates with the market to the benefit or detriment of the beneficial owner. TXU described that DICP is unique because it sits on TXU Business Services' books as a liability, which must be adjusted up or down to reflect the market value of TXU Corp.'s stock. Whatever the adjustments to the liability over time, the amount that is paid out to a DICP participant upon retirement or other qualifying payout event is the value of the TXU Corp. stock held for that participant at the time of payout. Ratepayers are never required to absorb any of the risk.[877]

TXU's Position

TXU Gas' proposed DICP adjustment is an example of a known and measurable adjustment for utility ratemaking. TXU provided testimony that the proposed DICP adjustment serves to normalize TXU Business Services' test year expenses by excluding the impact of an extraordinary, non-recurring, non-operating, accounting transaction.[878]

TXU addressed ACC's recommendation to disallow TXU Gas' adjustment related to TXU Business Services' DICP, based on ACC's assertion that this adjustment cannot be classified as known and measurable.[879] According to TXU, ACC's argument misrepresents the known and measurable adjustment that TXU is making with regard to DICP expense. Adopting it will create an absurd result that is wholly inconsistent with the concept that known and measurable test year ratemaking should reflect of the utility's ongoing cost of service.[880] TXU argued that its proposal is a known and measurable adjustment for utility ratemaking. The proposed DICP adjustment simply serves to normalize TXU Business Services' test year

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876 ACC Exhibit 4, Appendix C (TXU's response to ACC's RFI 1-151, attachment 1.
877 TXU Exhibit 28 at 6-8, 59.
878 TXU Exhibit 28 at 7-8.
879 TXU Initial Brief at 96-98.
880 TXU Exhibit 28 at 5.

expenses by excluding the impact of an extraordinary, non-recurring, non-operating, accounting transaction.[881] During the test year, the value of the stock held in the DICP for TXU Business Services' participants, which is carried on TXU's books for accounting purposes as a liability, declined by $9,040,661, due to a substantial drop in the TXU Corp. share price. As a consequence of that non-recurring event, the corresponding accounts payable balance declined by this amount. The corresponding accounting entry to this reduction in the amount payable was a decrease in expense of $9,040,661. The $9,040,661 credit to expense simply restates the liability associated with the DICP to current valuations based on market conditions. TXU Gas' proposed DICP normalization adjustment eliminates the impact of this extraordinary non-recurring event. Not making this adjustment would understate Distribution and Pipeline's known and measurable test year cost of service amounts by $565,014 and $356,202, respectively.[882]

TXU argued that if the Commission were to disallow the adjustment, it would assume that this extraordinary event was likely to occur each and every year implying that the price of TXU Corp. stock is expected to drop by more than $30 per share every year. TXU noted that this was a mathematical impossibility, considering the stock price is currently less than $30 per share.[883] TXU stated that no one can predict the increase or decrease in the TXU Corp. share price. Therefore, its proposed adjustment assumed no increase or decrease in TXU Corp. share price during the year. After making TXU's proposed adjustment, Distribution and Pipeline included approximately $150,000 and $109,000, respectively, in their proposed test year revenue requirement requests related to the cost of funding TXU Business Services' DICP program.[884]

ACC suggested that the proposed DICP adjustment requires TXU Gas customers to contribute additional revenues so that TXU executives can be protected from losses in TXU Corp. stock. TXU responded that ACC's position is inaccurate, reflects a fundamental misunderstanding of the DICP, and basic accounting principles. ACC stated that TXU's DICP adjustment creates a floor price on the common stock in the DICP for TXU Corp. senior management that minimizes or completely eliminates potential compensation losses and that this floor price is subsidized by TXU Gas customers rather than by TXU Corp. shareholders. TXU disagreed. The DICP adjustment does not establish a floor price for the common stock held on behalf of the DICP participants, nor does it eliminate the participant's potential compensation losses. Any loss or gain on the stock price is realized by the DICP participants, not TXU Gas' customers.[885]

ACC also stated that TXU is requesting recovery of an expense that may be reversed in the future if TXU Corp. common stock rallies from the levels during the test year.[886] TXU again disagreed with ACC's position. The purpose of TXU Gas' adjustment is not to recover an expense. TXU Gas' known and measurable adjustment serves to normalize the test year by eliminating this extraordinary negative expense amount. If TXU Corp.'s common stock price increases in the future, it will cause TXU Business Services' DICP liability to increase at the same rate. The corresponding accounting entry to this increase in the amount payable to DICP participants would be an equal increase in TXU Business Services' expense for

881 TXU Exhibit 28 at 7-8.
882 TXU Exhibit 28 at 5-6.
883 TXU Exhibit 28 at 5-6.
884 TXU Exhibit 28 at 59.
885 TXU Exhibit 28 at 6; TXU Reply Brief at 71-72.
886 ACC Exhibit 4 at 30.

that period. But TXU Gas and its shareholders would bear the burden of any such increase, not customers.[887]

ACC

ACC argued that TXU's proposed adjustments for its Deferred Incentive Compensation Plan (DICP) should not be approved because TXU did not prove that the DICP adjustment is reasonable and necessary, and known and measurable. ACC recommended a reduction to Account 923 to remove $565,014 from Distribution and $356,202 from Pipeline.[888]

ACC disagreed with TXU's description of the DICP adjustment as restating the liability associated with the DICP to current valuations based on market conditions and that the DICP adjustment is a normalizing adjustment necessary due to a decline in TXU stock prices during the test year. ACC asserted that TXU's stock prices declined during the test year as the result of the discontinuance of TXU's European business and the credit crisis that impacted the electric utility industry in 2002. ACC argued that if TXU's shareholders desire to protect the corporate officers from the impact of such events, they may do so. However, it is not reasonable and necessary for TXU's gas customers to be required to contribute additional revenues so that TXU executives can be protected from losses incurred due to events precipitated by TXU.

ACC argued that there is no known and measurable basis to support TXU's proposed adjustment. TXU Gas admitted that it cannot predict the price of TXU stock in the future. ACC recalled that TXU provided testimony that it did not predict the 2002 stock price decline, and that it is unknown what the price of the stock will be in 2004. ACC argued that TXU wanted gas customers to pay $921,216 more a year because the value of TXU stock declined in its executive stock savings program. ACC argued that this is unreasonable and recommended the Commission adjust Account 923 to remove $565,014 from Distribution and $356,202 from DICP costs.

ACC argued that ratepayers, who are already paying the salaries of all the upper management at TXU Gas, should not pay an additional $9 million each year to compensate them for a drop in stock price in a stock-based savings account as a result of poor management decisions. ACC argued that the DICP is a program that only benefits those TXU employees who are at high management positions at TXU and who can afford to defer 15 percent of their salaries to participate in this program. TXU then provides these high paid officers of the utility with further rewards by giving them another 22.5 percent boost (150 percent of deferred salary amount) to their salaries by buying TXU stock for them. ACC argued that these benefits should come at the expense of shareholders, not ratepayers.[889]

ATM's Position

ATM stated that, with regard to TXU's Performance Enhancement Plan and the Deferred Incentive Compensation Plan, it supports the adjustments proposed by ACC to reduce Distribution expenses by a total of $1,595,848 and Pipeline expenses by a total of $821,640.[890]

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[887] TXU Exhibit 28 at 7.

[888] ACC 4 at 27a; TXU Exhibit 61, WP/G-5.5(D), line 13; TXU Exhibit 61, WP/G-5.5(P), line 17.

[889] ACC Reply Brief at 68-69.

[890] ATM Initial Brief at 49.

Examiners' Recommendation
The Examiners recommend the Commission disallow TXU's request for expense adjustments related to its Deferred Incentive Compensation Plan (DICP). TXU did not provide meaningful, probative evidence that the adjustment requested is reasonable and necessary, or known and measurable. During the test year, the common stock held in the DICP was reduced by $9,040,661 due to the $30 per share decline in TXU Corp.'s common stock price.[891] TXU normalized the stock price in the test year to compensate for the decrease stock price. TXU provided no evidence showing that this decline was a non-recurring event. Instead, the evidence shows that TXU cannot know what will happen to the stock price in the future. TXU provided no probative, meaningful evidence that its normalization was reasonable and necessary for the provision of utility gas service. Although TXU can provide no evidence as to the future value of the stock, it requested the Commission allow it to recover an expense that may not exist if the TXU Corp. stock value increases. Therefore, it is reasonable for the Commission to disallow TXU's request for $565,014 from Distribution and $356,202 from Pipeline relating to the DICP adjustment.

6. Payroll Adjustment (Non-WINS)

The adjustments for TXU Gas - Distribution and TXU Gas - Pipeline for the test year ended December 31, 2002, are presented and described on Schedules G-5(D) and G-5(P) with additional details provided on the supporting schedules and workpapers that are included in the utility's rate filing package.[892]

TXU's Position
TXU addressed Dallas's arguments that the Commission should adjust TXU's payroll expense in the amount of $1,474,244 for TXU Gas - Distribution and $1,481,226 for TXU Gas - Pipeline, based on the concept that TXU's employee level declined by 256 employees, with approximately 196 of the employee reduction occurring after the test year end. TXU labor turnover reports provided in discovery, [893] provided the number of employees: (1) terminated (including the permanent reductions resulting from the WINS program); (2) hired; and (3) transferred between TXU entities.[894] TXU argued that Dallas ignored the last two categories of employees (new hires and transfers) and focused solely on the number of employees terminated.

[891] ACC Exhibit 4 at 29-30.
[892] TXU 17 at 10; TXU Exhibits $2,128,832 6, 7, and 61, Schedules G-5(D) and G-5(P).
[893] TXU's responses to Dallas's RFIs 1-017, 1-018, 18-01, 18-04, 20-06, and 20-07.
[894] TXU Exhibit 26 at 16;TXU Exhibit 30 at 6-8; TXU Exhibit 31 at 4-7.

Summary Table: TXU's Labor Turn-Over Reports[895]

Employee Action	Time Period 1/02 - 10/03	Time Period 11/03 - 12/03	Totals
Terminations	(256)	(5)	(261)
Hires	11	0	11
Transfers In	54	29	83
Number of Employees Off Payroll at End of Period	**(191)**	**24**	**(167)**
Reconciliation of Employee Actions:			
WINS Reductions - Permanent			121
Long-term Disability and Duplicate Listing in Termination Report			2
Open Positions at 12-31-03			44
Total Employee Changes			**167**

TXU argued that this table showed that 261 employees were terminated through December 2003. However, as explained in response to ACC and Dallas RFIs (12-57 and 7-03, respectively), 121 of these terminations were permanent reductions resulting from the WINS program. The difference between the total of 261 terminations and the 121 permanent reductions is 140 terminations that were not permanent reductions because they required replacements (i.e., retirements, resignations, long-term disability, and poor job performance). TXU explained that the majority of the non-permanent reductions were "filled by 11 new employees from the external job market and 83 existing employees transferring from other areas of the Company." As of December 2003, only 44 non-permanent reductions were unfilled pending the selection of skilled candidates.[896]

TXU argued that Dallas's recommendation to decrease labor expense by almost $3 million failed to consider and calculate the number of permanent reductions of employees. Dallas's calculation is a selective analysis of employee counts that skews the actual TXU Gas staffing level. Simply stated, TXU has not experienced the staffing reduction of 256 employees suggested by Dallas nor has it experienced any significant change in staffing levels that have not already been accounted for in the utility's requested cost of service.[897] TXU argued that Dallas's recommendation be denied because it is based entirely on flawed calculation of the number of TXU Gas employees terminated as a result of the WINS program.

Dallas's Position

Dallas argued that TXU's payroll request reflects actual test year levels. TXU then adjusted for WINS-

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[895] TXU Initial Brief at 61.

[896] TXU Exhibit 26 at 16;TXU Exhibit 30 at 6-8; TXU Exhibit 31 at 4-7; TXU Initial Brief at 61; Tr. Vol. 7 at 177.

[897] TXU Exhibit 26 at 16; Tr. Vol. 7 at 175-179.

related cost reductions. Dallas reviewed TXU's monthly termination reports to determine that additional Distribution and Pipeline employees were terminated. Recognition of the corresponding lower payroll already in effect reduces Distribution by $2,128,832 and Pipeline payroll by $2,121,759.[898] Dallas proposed these amounts as reductions to TXU's proposed expenses.

The one thing that TXU and Dallas agree upon is that in December 2003, TXU had 44 vacant positions.[899] Dallas's proposed reductions to TXU's requested expenses are for non-WINS related payroll. At Dallas Exhibit 1, page 30, Dallas provided a table describing the proposed adjustments to payroll. Dallas based its calculation on the 256 employees terminated to recommend reduction of $1,474,244 for Distribution and $1,481,226 for Pipeline. Dallas assumed an average salary of $45,000 per year. Dallas added employee benefit adjustments basing its employee benefit adjustments on the relationship between TXU's proposed benefit reduction and its corresponding labor reduction. The employee benefit factor was 44.12 percent. Instead of using the 44.12 percent benefit factor, Dallas used the more conservative benefit factor of 36.54 percent based upon the WINS adjustment at workpaper G-5.11(D). The resulting calculation was a reduction of employee benefits of $538,689 for Distribution and $541,240 for Pipeline. Dallas also added payroll tax adjustments, based upon TXU's payroll tax rate of 7.8616 percent for Distribution and 6.7035 percent for Pipeline. The resulting payroll tax adjustment would be $115,899 for Distribution ands $499,294 for Pipeline. Dallas's position is summarized in the following table.

Dallas's Summary Table: Payroll and Payroll-Related Adjustments[900]

DESCRIPTION	DISTRIBUTION	PIPELINE	TOTAL
Payroll Expense	$4,319,974	$2,459,266	$6,779,240
WINS Labor Adjustment	($2,845,730)	($978,040)	($3,823,770)
Additional Labor Adjustment	$1,474,244	$1,481,226	$2,955,470
Benefits	$538,689	$541,240	$1,079,929
Payroll Taxes	$115,899	$99,294	$215,193
Total	$2,128,832	$2,121,759	$4,250,591

Dallas argued that TXU made an incorrect assumption. Dallas's recommended adjustments were not based upon 256 employees.[901] It was based upon the 44 vacant positions. Dallas stated that TXU's rebuttal testimony does not address the same reductions as proposed by Dallas.[902]

Dallas noted that TXU's Initial Brief contains statements that are inconsistent with discovery responses.[903] Dallas explained that its recommendation does not relate to employees who transferred within the TXU Corp. Instead, Dallas argued, its recommendation relates to permanent reductions to TXU's workforce.[904]

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898 Dallas Initial Brief at 39; Dallas Exhibit 1 at 28-30; Dallas Exhibit 1, attachment JP-1; TXU Exhibit 61, WP/G-5.11(D).
899 Tr. Vol. 10 at 75-76.
900 Dallas Exhibit 1 at 30.
901 Tr. Vol. 7 at 175-179.
902 Dallas Initial Brief at 38-39.
903 Dallas Reply Brief at 12.
904 Dallas Reply Brief at 12.

ATM's Position
ATM stated that it supported Dallas's adjustments related to payroll costs, benefits and taxes to reduce Distribution expenses by $2,128,832 and Pipeline expenses by $2,121,760.[905]

Examiners' Recommendation
The Examiners recommend that the Commission make no adjustment to TXU's Payroll expense request beyond the additional WINS savings. The evidence shows that Dallas's recommendation to decrease labor expense did not consider that TXU Gas has not experienced a permanent staffing reduction of 256 employees.[906] In the WINS section of this PFD which begins on page 34, the Examiners recommended that TXU Gas ratepayers receive additional beneficial savings amounts. The evidence shows that with that additional WINS savings, no additional payroll adjustment is reasonable. No additional reduction for staff reductions, as recommended by Dallas and discussed in this section of the PFD is necessary to result in a reasonable payroll expense for TXU.

7. Federal Income Tax

One of the components of expense usually allowed by the Commission is tax. Tax is generally considered in one of two categories. First, federal income tax, also known as FIT, is based upon revenues and expenses. Second, taxes other than income tax component includes such items as payroll taxes, ad valorem taxes, Texas franchise tax, and sometimes the U.S. Department of Transportation's pipeline user fee. Taxes included in TXU's calculation do not include tax categories for which the utility acts as a collector and merely remits collected amounts to another entity, such as a municipality.

TEX. UTIL. CODE §104.055 (c) and (e) provide that tax is to be based upon revenues and expenses and that tax is not intended to increase gas utility rates that are not caused by gas utility service. In other words, the utility's rates may include only expenses caused by gas utility service. As contemplated by the statute, the Commission should approve amounts for FIT proved by TXU to be no more than the utility will pay in tax. The ratepayer, who pays to the utility its revenues, should receive the benefits of any tax savings enjoyed by the utility. Commission Rule §7.501(2) requires a gas utility to present evidence of the amount of any income tax savings or deferrals derived from the application of such methods as liberalized depreciation or amortization.

TXU's Position
TXU argued that FIT expense was computed based on revenues and expenses included in the requested revenue requirements. Total tax expense included in the cost of service equals the statutory income tax rate (currently 35 percent)[907] times the regulated book net income before taxes, adjusted for the tax effects of non-normalized differences between book income and taxable income. The difference between total normalized FIT expense based on book net income and the amount of the current tax liability actually

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[905] ATM Initial Brief at 29.
[906] TXU Exhibit 26 at 16; Tr. Vol. 7 at 175-179.
[907] No party contested that 35 percent is the generally accepted statutory income rate. Although no witness provided testimony regarding the origins of the 35percent tax rate, see 26 USCA §11 (2002) codifying P.L. 103 - 66 §1322, Omnibus Budget Reconciliation Act of 1993, approved August 10, 1993, effective January 1, 1993, which raised the tax rate from 34 percent to 35 percent.

reflected on the FIT return is recorded as deferred FIT. The deferred tax is subsequently amortized over the life of the asset or other basis that gives rise to the tax benefit or increase.[908] TXU also noted that no intervening party took issue with this testimony. The utility also acknowledged that the actual federal income tax figures are dependant upon the Commission's decisions as to the utility's cost of service – especially its return on invested capital.[909]

Intervening Parties' Positions
Dallas had two recommendations regarding FIT. First, Dallas proposed an adjustment to FIT without an adjustment to the methodology used by TXU to calculate FIT. In accordance with the modifications Dallas recommended regarding invested capital and the change in rate of return, Dallas recommended that FIT expense would also have to be reduced.[910] Dallas also recommended that tax preparation costs be excluded from expenses associated with TXU Business Services because the utility failed to provide evidence relating to its consolidated tax savings.[911] Dallas argued that TXU's proposed taxes are hypothetical and bear no relationship to the actual amount of income taxes paid on a consolidated basis. Dallas argued that ratepayers were not assigned any of the benefits associated with the corporation's filing of a consolidated tax return. Therefore, the ratepayer should not be burdened with the cost of preparing income tax filings. Dallas went as far as to say that TXU refused to provide the data to allow the calculation of a consolidated tax savings.[912]

Examiners' Recommendation
The Examiners were unable to locate any previous Commission consideration regarding consolidated tax savings. To the Examiners' knowledge, this is a matter of first impression for the Railroad Commission. TXU failed to provide adequate information to the parties, to the Examiners, and to the Commission that would have allowed for complete evaluation and consideration of the reasonableness of its request for inclusion of FIT in invested capital. Therefore, because TXU did not meet its burden to prove its request for amounts to be included in invested capital for FIT were reasonable and necessary, and because TXU failed to present evidence of the amount of any income tax savings in accordance with Commission Rule §7.501(2), the Examiners recommend the Commission disallow all amounts for federal income tax.

Rather than filing individual tax returns for each subsidiary, a parent company, like TXU Corp., will make a consolidated federal income tax return on behalf of it and its various subsidiaries. Consolidated tax savings are the amounts saved by a parent company's use of a consolidated federal income tax return. The consolidated tax filing results in annual consolidated taxable income for the parent company and subsidiaries that is, in most instances, less than the combined taxable incomes of the affiliated subsidiaries with gains calculated on a stand alone basis. A large corporation is likely to benefit from the use of a consolidated tax filing because the corporation is able to take its current losses against its current gains, thereby realizing the value of an affiliate's loss today, rather than having to wait until a later time when the affiliate has a gain. In other words, a consolidated tax filing allows for the corporation to realize the advantage of the time value of money. This concept is also used in corporations with utility subsidiaries. The corporation may use the income of the regulated utility to offset losses, if any, of its unregulated

[908] TXU Exhibit 19 at 3. This testimony was subsequently adopted by TXU witness Moseley.
[909] TXU Initial Brief at 99 (Mar. 8, 2004).
[910] Dallas Exhibit 2 at 36 (Pous Direct Testimony).
[911] *See* Consolidated Tax Returns, Internal Revenue Code, 26 USCA §§1501 -1505 (2002 and Supp. 2003).
[912] Dallas Exhibit 1 at 53-54.

subsidiaries.

Even though it was TXU's burden to prove the reasonableness of its invested capital requests, including its request for FIT, TXU did not provide evidence of the amount, if any, of savings that would be realized by a consolidated tax filing. In this proceeding, the parties, Examiners, and Commission were not furnished with sufficient information to determine whether a savings would be realized from a consolidated tax filing. The Examiners find that, consistent with TEX. UTIL. CODE §104.055 (c) and (e), ratepayers who produce the utility's income should share in the tax benefits. The Examiners also find that failure to recognize tax savings that would result from the filing of a consolidated return would, in effect, be allowing a tax allowance in excess of the actual tax requirement. Therefore, the Examiners recommend the Commission disallow all requests for FIT.

This may be the first time this Commission has considered the consolidated tax savings issue; however, this is not the first time TXU has faced this issue. TXU frequently has matters before the Public Utility Commission of Texas. The Public Utility Regulatory Act (PURA) §36.060 requires that unless it is shown to the satisfaction of the regulatory authority that it was reasonable to choose not to consolidate returns, an electric utility's income taxes shall be computed as though a consolidated return had been filed and the utility had realized its fair share of the savings resulting from that return, if: (1) the utility is a member of an affiliated group eligible to file a consolidated income tax return; and (2) it is advantageous to the utility to do so. PURA explicitly requires TXU Electric to consider consolidated tax savings. It is not inconsistent to read the Gas Utility Regulatory Act as requiring TXU Gas to construe its tax to the benefit of the regulated ratepayer, particularly because TEX. UTIL. CODE §104.055 (e) provides that the section "is not intended to increase gas utility rates to the customer not caused by utility service. Utility rates may include only expenses caused by utility service." In this proceeding, TXU should have passed the savings to the ratepayer or, in the alternative, should have presented evidence that no savings would be realized by a consolidated tax filing. TXU did not show that a consolidated tax filing would result in a savings to the ratepayer. TXU did not show that there would be no savings realized by the use of a consolidated tax filing. Because the record contains no evidence, the Examiners cannot find that TXU's request is reasonable.

Neither can the Examiners recommend a partial allowance and partial disallowance of FIT expense, because there is no evidence in the record to support that result. There is no evidence to allow the Examiners to even consider that a credit to ratepayers for a portion of the consolidated tax savings realized by the parent company in the form of an invested capital adjustment might be appropriate. The record is devoid of any evidence as to the savings of a consolidated tax filing. Because the record contains no evidence, the Examiners cannot find that TXU's request is reasonable and cannot recommend that TXU be allowed any amounts for FIT.

Texas has previously dealt with a very similar situation. In Public Utility Commission (PUC) Docket No. 14965, the PUC found that it was appropriate to require a consolidated tax savings adjustment. In an appeal of that docket, the Third Court of Appeals deemed the PUC's calculation *methodology* to be acceptable, but ultimately upheld the District Court's reversal for *lack of record evidence* supporting the

PUC's alternative calculation.[913] Therefore, because the Examiners in this proceeding have found that TXU presented no evidence showing whether the consolidated tax filing would provide savings to the gas utility customers or the amount of savings that would be realized from a consolidated tax filing, TXU should be denied its request for costs of tax filing preparation. Without evidence in the record regarding a consolidated tax savings, a partial allowance and disallowance of FIT expense could be likely construed by Texas' courts as unsupported.

8. Taxes Other Than Income Taxes and State Franchise Tax

TXU proposed that the following taxes (taxes other than income tax) be included in TXU Gas' cost of service: payroll taxes, ad valorem taxes, revenue related taxes, U.S. Department of Transportation pipeline user fees, and Texas' franchise tax.[914] Revenue related taxes include state gross receipts tax, local gross receipts tax, and the gas utility tax. TXU proposed the expense amount to be attributed to each tax.[915]

Intervening Parties' Positions
No intervenor opposed TXU's proposal that the identified taxes be included in TXU Gas' cost of service. No intervenor opposed the reasonableness of the expense amount to be attributed to each tax. However, ACC identified an error in TXU's calculation of the state franchise tax expense for Distribution net taxable capital.[916] ACC also identified a transcription error in TXU's calculation of the state franchise tax expense for Pipeline.[917] TXU agreed with ACC's comments and revised its testimony, schedules, and workpapers, accordingly.[918]

Examiners' Recommendation
The Examiners find that it is reasonable to include payroll taxes, ad valorem taxes, revenue related taxes, U.S. Department of Transportation pipeline user fees, and state franchise taxes in TXU's cost of service.

The evidence shows that approval of an amount of state franchise tax using the net Taxable Capital Method is reasonable. In Texas, corporations calculate the tax due on net taxable capital and the tax due on net taxable earned surplus, and pay the greater of the two. The Texas Corporation Franchise Tax Report (Form 05-142; 05-143), requires two calculations: (1) tax due on net taxable capital and (2) net tax due on net taxable earned surplus.

TXU claimed that it is the TXU Gas entity that makes the franchise tax filing.[919] In test year 2002, TXU Gas paid a total of $307,440 in state franchise tax. TXU Gas stated that it had a stand alone net operating loss for the year. Therefore, TXU adjusted its state franchise tax to reflect the taxable capital and earned

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913 *Application of Central Power and Light Company for Authority to Change Rates*, Docket No. 14965, Second Order on Rehearing (Oct. 16, 1997); *Central Power and Light Company v. Public Utility Commission*, 547 S.W.3d 547 (Tex. App.-Austin 2000, writ requested).
914 TXU Exhibit 20 at 3-6.
915 TXU Exhibit 61, Schedule G-6(D) and Schedule G-6(P).
916 ACC Exhibit 2 at 4.
917 ACC Exhibit 2 at 7.
918 ACC Exhibit 40; TXU Exhibit 61, Schedules G-6(D) and G-6(P).
919 TXU Exhibit 20at 6; TXU Exhibit 61, WP/G-6.3(P), Note at lines 20-22.

surplus at the proposed rate.[920] In TXU Exhibit 61, the utility's corrected calculation of franchise tax under the Taxable Capital Method resulted in $396,420.88 for Pipeline and $1,242,084.81 for Distribution.[921] Under the second method, i.e., the Taxable Income Method, the state franchise tax calculation was $648,158.16 for Pipeline and $2,134,685.37 for Distribution. However, the Examiners find that TXU did not provide clear evidence regarding its franchise tax calculation and treatment.[922] The Taxable Capital Method appears to calculate *less* tax than the Taxable Income Method. Nevertheless, at the bottom of Workpaper WP/G-6.3(P) of TXU Exhibit 61, TXU included the note that "[f]ranchise tax is remitted to the state based on total TXU Gas, which under proposed rates would be calculated under the Taxable Capital Method." TXU provided no evidence or testimony to explain how or why the *TXU Gas* calculation of franchise tax would have a different result than the individual *Pipeline* and *Distribution* calculations of franchise tax, such that TXU would remit using the lower Taxable Capital Method rather than the higher Taxable Income Method. The evidence did not provide for amounts of loss that were considered by TXU in each calculation. The evidence did not support the higher calculation method. The evidence did not provide any other possible explanation.

Basing the state franchise tax expense on the Taxable Capital Method results in a more accurate cost of service than the Taxable Income Method and the record lacks evidence to support the Taxable Income Method; therefore, the Examiners recommend the Commission approve state franchise tax expense calculated using the Taxable Capital Method. The Examiners' recommendation as to the expense amounts to be attributed to each tax (taxes other than income tax) is contained in Examiners' Schedule N(D) and Schedule N(P).

The Examiners recommend that, as a compliance filing, the Commission require TXU Gas to file with the Railroad Commission a copy of its Texas Corporation Franchise Tax Report (Form 05-142; 05-1243) at the time it is filed each year with the Texas Comptroller.

9. Pensions and Other Employee Benefits

TXU sought approval from the Commission for Pension and Other Employee Benefits as an expense. TXU represented that the amounts reflect the normal ongoing costs of TXU Gas operations. TXU stated that no Intervening Party challenged the utility's request.

For Pipeline, TXU reported test year costs of $5,760,899.47 and an adjustment of $2,580,097.75, for a total of $8,338,021.46.[923] For Distribution, TXU reported test year costs $16,106,271.77 and an adjustment of $5,286,036.69, for a total of $21,518,788.41.

Examiners' Recommendation

The Examiners find little evidence to substantiate TXU's position that these amounts and adjustments are reasonable and necessary.[924] However, in the absence of contravening testimony, the Examiners

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920 TXU Exhibit 20 at 6.

921 TXU Exhibit 61, WP/G-6.3(D); TXU Exhibit 61, WP/G-6.3(P).

922 TXU Exhibit 61, WP/G-6.3(D); TXU Exhibit 61, WP/G-6.3(P).

923 TXU Exhibit 17 at 10; TXU Exhibit 61, Schedule G-5.7(P); TXU Exhibit 61, Work paper WP/G-5.7(P); TXU Initial Brief at 90 (Mar. 8, 2004).

924 TXU exhibit 17 at 10; TXU Exhibit 6,7, and 61, Schedules G-5(D) and G-5(P).

recommend the Commission approve TXU's requested amounts.

10. Poly 1 Pipe/Safety Compliance Program Expenses

The issue of Poly 1 pipe, TXU's Safety Compliance Program, and TXU's requested treatment is discussed starting at page 13 The Examiners recommended that TXU's request for a return on assets be denied. The Examiners also recommended that the Commission require TXU, from the date of this Order on a forward-going basis, to cease collection in rates for Poly 1 pipe expenses. TXU stated that expenses for Poly 1 pipe have been previously approved by the Commission and by municipalities. However, this is the first time the issue has been fully litigated and is therefore ripe for decision. The Examiners recommend that the Commission disallow a return on the Poly 1 pipe Safety Compliance Program Costs, denial of these expenses as invested capital from the date of the Commission's Order, denial of related legal and lawsuit expenses, and denial of the amortization of the Poly 1 pipe software. TXU's proposed Safety Compliance Program amortization expense of $3,008,705 is discussed further, starting on page 13 of this Proposal for Decision.

11. WINS Expenses

The issue of WINS is discussed starting at page 34. The Examiners recommended that no WINS program implementation costs are attributable to TXU Gas' utility customers. The Examiners also recommend that the beneficial savings resulting from the WINS program should be increased.

12. Pipeline Integrity Testing

The Commission's rule §8.101, *Pipeline Integrity Assessment and Management Plans for Natural Gas and Hazardous Liquids Pipelines* (16 TEX. ADMIN. CODE §8.101,[925] "Pipeline Integrity Rule"), requires gas utilities in Texas to assess the integrity of their pipeline systems and to repair or replace pipe that does not meet safety standards. Utilities that desire to use a direct assessment methodology as an inspection and assessment tool were required to prepare a direct assessment plan and to submit the plan to the Commission for review and approval. The Pipeline Integrity Rule requires that at least one-half of a gas utility's pipeline be assessed by January 1, 2006, and the remainder by January 1, 2011.[926] TXU reported that the GUD 9400 test year of 2002 was the first year the utility operated under its integrity management plan, in compliance with the Pipeline Integrity Rule.[927] TXU reported that its O&M expenses associated with pipeline assessment included pressure tests, in-line inspections, modifications to pipes to complete pressure tests, and the cost to maintain gas service to customers during the tests.[928]

TXU

TXU Distribution experienced no integrity testing costs during the test year.[929] TXU Pipeline experienced

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[925] §8.101 was effective April 30, 2001, 26 Tex Reg 3214; amendment effective August 25, 2003, 28 Tex Reg 6829.

[926] 16 TEX. ADMIN. CODE §8.101(b)

[927] TXU Exhibit 13 at 12-13; TXU Gas Exhibits 6-8 and Exhibit 61 at Schedules G-5.8(D), G-5.8(P), WP/G-5.8(D), and WP/G-5.8/1-2(P).

[928] TXU Exhibit 13 at 12.

[929] ACC Exhibit 4 at 9a (Nalepa Direct Testimony).

$3,763,720 of integrity testing costs during the test year[930] for assessing 277.2 miles of pipeline at an average cost of $13,577 per mile. TXU reported that as of January 1, 2003, the utility had 1,454 miles to assess before its 50 percent deadline on December 31, 2005. TXU estimated its total capital cost to comply with the December 2005 deadline to be $28.3 million.[931]

TXU requested recovery of additional integrity testing costs through 2005. The annual adjusted amount TXU proposed for Distribution was $683,376. TXU's calculation for this amount is located at WP/G-5.8 (D). TXU assumed that it would assess approximately fifty miles in 2003, fifty miles in 2004, and fifty-one miles in 2005 (average = 50.33 miles for the three years). TXU calculated that it assessed its pipeline at approximately $13,577 per mile during the test year. Therefore, TXU estimated that its three year average was $683,376.[932] TXU sought this amount of $683,376 as its yearly adjustment for Distribution.

TXU reported that it had $3,763,667 of actual test year 2002 integrity testing costs attributable to Pipeline.[933] TXU estimated the amount needed for 2003, 2004, and 2005 would average $6,424,944.[934] Therefore, TXU proposed an adjustment. The annual adjusted amount TXU proposed for Pipeline was $2,661,277.[935] TXU's calculation for this amount is located at WP/G-5.8/2(P). TXU assumed that it would assess approximately 434 miles in 2003, 434 miles in 2004, and 434 miles in 2005. TXU calculated that it assessed its pipeline at approximately $13,577 per mile. The $13,577 per mile, times 434 miles, is $5,892,418. Then, TXU added verification costs of $528,000 to total $6,420,418 ($5,892,418 + $528,000 = $6,420,418). The three year average was estimated by TXU to be $6,424,944. Considering that the test year 2002 costs were $3,763,667, TXU determined that the adjustment it needed was $2,661,277. TXU sought approval of $2,661,277 as its yearly adjustment for Pipeline.[936]

ACC opposed TXU's adjustment, in part, and ATM opposed TXU's adjustment, in total. TXU argued that ACC's and ATM's recommendations were unreasonable and must be rejected. TXU stated that its proposed adjustment to account for the increased expenses associated with the Pipeline Integrity Rule are known, measurable, and reasonable.[937]

TXU countered ACC's proposal and argued that no efficiencies can be gained by creating an integrated testing program between TXU Gas and TXU Fuel Company because such an integrated testing program is already in place; [938] that TXU Gas cannot simply exempt pipeline segments from the required assessments merely by transferring the assets between operating divisions;[939] that there are significant operational constraints that prevent the utility from merely transferring assets to avoid compliance with a Commission rule;[940] and that it is not possible, as suggested by ACC, to reclassify certain segments of

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930 ACC Exhibit 20.
931 TXU Exhibit 13 at 12.
932 TXU Exhibit 61 at Schedule G-5 (D), line 8; WP/G-5.8(D); ACC Exhibit at 9a; and ACC Exhibit 20.
933 WP/G-5.8/2(P), Line 10.
934 WP/G-5.8/2(P), Line 11.
935 WP/G-5.8/2(P), Line 12.
936 TXU Exhibit 61 at Schedule G-5 (D), line 8; TXU Exhibit 61 at Schedule G-5 (P), line 8; TXU Exhibit 13 at 12, line 27; ACC Exhibit 20, attachment 1.
937 TXU Initial Brief at 115-118 (Mar. 8, 2004); TXU Reply Brief at 81 - 83 (Mar. 17, 2004).
938 TXU Gas Exhibit 26 at 12.
939 TXU Gas Exhibit 26 at 13.
940 TXU Gas Exhibit 26 at 13; Tr. Vol. 7 at 183-185.

pipeline and to operate at reduced pressures.[941]

TXU stated that ATM's proposal was to disallow all adjustment amounts attributable to the pipeline integrity program and that ATM's proposal was based on incorrect and unfounded assertions. TXU concluded that:

- the utility considered compliance with the Commission's existing Pipeline Integrity Rule only, and not any present or future federal rules, when developing its adjustment to its cost of service;[942]
- the utility will comply with the rule to assess 50 percent of the necessary mileage by 2005, because it has a flexible plan to allow for the necessary mileage by 2005;[943]
- the utility based its adjustment on its test year experience in complying with the Pipeline Integrity Rule and disclosed during discovery all costs and activities undergone during the test year to comply with the Integrity Rule and the test year cost per mile is representative of the expected costs in the future;[944]
- TXU disclosed that TEPSCO was the project manger for 2003 and the term of the contract with TEPSCO does not expire until 2008;[945]
- TXU presented and used the costs associated with its experience in complying with the Pipeline Integrity Rule as the basis for its adjustment;[946]
- TXU will use approved methodologies to assess the pipeline segments under the Pipeline Integrity Rule;[947] and
- if TXU's direct assessment methodology is approved, the utility will use the methodology to assess pipeline segments, but the costs associated with direct assessment are no less than the estimated cost per mile included in the utility's proposed adjustment;[948] and
- increased numbers of customers and revenues have no relationship to how much it costs to assess its pipelines, as required by the Pipeline Integrity Rule.

ACC

ACC argued that the adjustment requested by TXU was not warranted and questioned the credibility of TXU's witness on this issue.[949] ACC argued that TXU failed to demonstrate that its proposed adjustment is known and measurable or that the expenses are reasonable and necessary. ACC recommended an integrity testing reduction of $9,413 for Distribution and $1,045,747 for Pipeline to remove redundant verification costs and implementation of identified cost savings initiatives.[950]

ACC took the position that the Pipeline Integrity Testing Program expense adjustment proposed by TXU was not reasonable and necessary, nor was it a known and measurable adjustment. ACC challenged that

941 TXU Gas Exhibit 26 at 14; Tr. Vol. 7 at 183-185.
942 TXU Gas Exhibit 26 at 7-11.
943 Tr. Vol. 2 at 65.
944 TXU Exhibit 13 at 11-13; TXU Exhibit 26 at 8; TXU Exhibit 26, attachment JAG-R-2; and TXU Exhibit 26, attachment JAG-R-3.
945 TXU Exhibit 26 at 9; TXU Exhibit 26, attachment JAG-R-4.
946 TXU Exhibit 26 at 8; Tr. Vol. 2 at 51-52.
947 TXU Exhibit 26 at 9; TXU Exhibit 26, attachment JAG-R-4; Tr. Vol. 2 at 60-65.
948 TXU Exhibit 26 at 10; Tr. Vol. 2 at 61 and 159-160; Tr. Vol. 7 at 186.
949 ACC Initial Brief at 131-133 (Mar. 8, 2004); ACC Reply Brief at 76 (Mar. 17, 2004).
950 ACC Exhibit 4 at 10a.

TXU's integrity testing costs are not known and measurable because TXU testified that it will continue to look for ways to reduce its integrity testing costs, and because future integrity testing costs are determined by the condition of the specific section of pipe being tested.[951] ACC reported that TXU's expense calculation for its proposed adjustment includes redundant verification costs of $7,970 and that because TXU did not rebut ACC's adjustment for redundant verification costs the calculation of integrity costs should be adjusted by this amount.[952]

ACC argued that TXU should be able to achieve cost savings through coordinated pipeline integrity testing between TXU Gas and TXU Fuel Company and recommended that TXU's proposed expenses for program management could be reduced by 5 percent as costs that could be saved through coordination of project management teams between TXU Gas and TXU Fuel.[953] ACC pointed out that TXU adopted the cost saving measure it recommended, but continues to object to an adjustment to its expenses to recognize those savings. ACC argued that its 5 percent recommendation resulted in a $44,075 adjustment to TXU's proposed costs and should be approved.[954]

ACC noted that it was actually TXU's own staff that considered the possibility that reclassification of the pipe that is subject to integrity testing requirements could be one way to reduce costs. ACC recommended that the costs savings of any such reclassification should be reflected in TXU's proposed cost adjustment. ACC suggested that TXU be required to affirm that it will not take such action to reclassify pipe, as recommended by TXU's Gas Initiatives Pipeline Integrity Team.[955]

ACC summarized the effect of its recommendations on the recalculation of a per-mile cost. ACC removed $7,970 in redundant verification costs and $44,075 to reduce project costs for total adjustments of $52,045. Therefore, ACC's recalculation of the test-year-per-mile cost was $13,390 per mile ($3,763,666.60 - $52,045 ÷ 277.2 miles = $13,390).[956]

ACC applied this rate to Pipeline. ACC acknowledged that milage was reduced by 72 miles per year due to reductions in the amount of pipe subject to testing ($13,390 x [434.3 - 72] = $4,851,197). ACC then added verification cost of $528,000 to calculate total Pipeline integrity testing costs of $5,379,197, which is a reduction of $1,045,747 from the amount requested by TXU.[957]

ACC did not adjust the amount of Distribution pipe. Therefore, ACC applied its adjusted test year per-mile expense to the miles estimated by TXU ($413,390 X 151 miles/3years) to calculate $673,963. ACC determined that this was a reduction of $9,413 from the amount sought by TXU.[958]

ATM

ATM argued that TXU's proposed adjustment for future expenses through December 31, 2005, are not

[951] ACC Initial Brief at 132(Mar. 8, 2004); Tr. Vol. 2 at 57 and 63.
[952] ACC Exhibit 4 at 10a.
[953] ACC Exhibit 4 at 13 - 14.
[954] ACC Exhibit 4 at 12; TXU Exhibit 26 at 12-13; Tr. Vol. 2 at 103-105.
[955] ACC Initial Brief at 132-134; ACC Exhibit 4 at 11- 16a; TXU Exhibit 26 at 13-14.
[956] ACC Exhibit 4 at 16a.
[957] ACC Exhibit 4 at 17a.
[958] ACC Exhibit 4 at 17a.

known and measurable. ATM argued that because the expenses have not been incurred, TXU cannot know what its integrity assessment costs will be. ATM argued that TXU's adjustment calculation is flawed. TXU took its test year expenditure while in start-up mode and divided it by the number of miles assessed to arrive at a cost per mile.[959] ATM represented that TXU had provided no evidence that 2002 costs were representative of the costs TXU will incur in 2003, 2004, or 2005, or that the costs of repairs made in 2002 are similar to the amounts that will be incurred in future years.[960]

ATM questioned why TXU replaced Fluor Daniel at the end of the test year as the project manager and noted that TXU never explained why. Because TXU provided no clear explanation, ATM assumed that it was because Fluor Daniel was not performing well. ATM suggested that the costs for the 2003 project manager, TEPSCO or Tellepsen, were unknown and it was also unknown whether TEPSCO or Tellepsen would continue as the project manager in 2003, 2004, and 1005.[961]

ATM also questioned TXU's record of scheduling, rescheduling, and completion of capital projects. ATM noted that TXU's explanation for no assessment activity in the first four months of 2003 was that it was a peak period for gas consumption. However, ATM asserted that March and April are not peak consumption months and questioned why TXU's witness was unable to determine whether assessments had been performed in the first four months of test year 2002.

ATM listed several other uncertainties regarding future costs. One was TXU's number of test verifications and estimate of test verification costs, because the number of tests and the costs of those tests varied from 2001 to 2002, and TXU was not certain how many test verifications will be made in 2003, 2004, and 2005.[962]

Examiners' Recommendation

TXU failed to meet its burden regarding pipeline integrity assessment and testing costs. The Examiners make two recommendations. First, the Examiners recommend that the Commission disallow $881,499, which is the amount TXU Gas spent in test year 2002 for Fluor Daniel Project Management services.[963] The record evidence does not show that TXU's decision to use Fluor Daniel as the initial project manager was prudent, reasonable, or necessary. Second, TXU's evidence relating to its estimated calculation of the 2003, 2004, and 2005 integrity testing costs is speculative and unreliable. Therefore, the Examiners recommend that the Commission deny TXU's proposed adjustments to both Pipeline and Distribution, because TXU did not meet its burden to prove that these amounts for future integrity testing costs are known and measurable changes. The Examiners' recommendations regarding the treatment of Pipeline Integrity Testing expenses are discussed more thoroughly in the following paragraphs.

The Examiners have thoroughly reviewed all evidence on this issue, including the January 27, 2004, hearing transcript. The Examiners considered TXU's explanation regarding the project management.[964] Mr. Greer stated that Fluor Daniel (Fluor) supplied other services for the TXU companies and was initially

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959 ACC Exhibit 20; ATM Initial Brief at 58.
960 ATM Exhibit 1 at 36-37.
961 ATM Exhibit 1 at 37.
962 ATM Exhibit 1 at 37-39.
963 ACC Exhibit 20, RFI Response to ACC 1-118, Attachment 1, line 23.
964 Tr. Vol. 2 at 101 - (Jan. 27, 2004).

selected for the integrity testing program because there was already an a structure (negotiated rates) in place that would allow TXU to use the services from Fluor Daniel. However, Greer was unsure as to whether Fluor Daniel had previously provided services for TXU Gas, could not provide the date the arrangement between Fluor and TXU was initiated, and was vague about the nature of the services that Fluor was under an existing arrangement to provide.

The Examiners find that TXU did not provide probative evidence regarding the services or results that Fluor actually provided to TXU. The extent of Mr. Greer's description was that Fluor provided general engineering, project management, program management, and services that TXU did not have in-house staff to do, but were necessary.[965] Mr. Greer stated that his responsibility with regard to the pipeline integrity testing was day-to-day management of the project, to make sure that TXU had a plan in place, and to make sure that the plan got implemented. However, Mr. Greer stated that he did not know the name of the person from Fluor who was in charge of the project, that no one from Fluor reported to Mr. Greer, and that he was not sure where the Fluor management team was located, or where the Fluor office staff was located.[966]

Fluor did not do all the work; Fluor contracted with TEPSCO.[967] Mr. Greer was not certain how many contractors under Fluor were involved. Mr. Greer didn't know the arrangement or contractual obligation between TXU and TEPSCO. Mr. Greer stated that he believed TEPSCO took its direction from Fluor but may have actually had a commercial arrangement with TXU Gas.[968] Mr. Greer did not know whether TEPSCO had contracted with other companies for similar services.[969] The Examiners find that TXU failed to present probative evidence why the utility referred to the new project manager as Tellepsen Services Company, L.P., stating at the hearing that TXU offered the wrong name and that TEPSCO was the appropriate name.[970]

When questioned as to why Fluor was replaced with TEPSCO, TXU offered no probative evidence. Mr. Greer gave no reason for TXU's decision to solicit bids after Fluor had been the project manager for a year. Instead, Greer testified that TXU knew it had other options for the services that were performed by Fluor, and that it was prudent business practice to test the market and understand TXU's options. The Examiners note the evidence shows TXU did not solicit bids or consider any other company when Fluor became the initial project manager. TXU offered no evidence that it was able to procure a preferred contractual arrangement with TEPSCO for a more economical cost, for better service, or for different test verification analysis.

The Examiners find that the evidence shows that TXU did not solicit bids and did not consider any company other than Fluor as the initial project manager. The evidence does not show that TXU Gas was required or contractually obligated to use Fluor as the initial project manager. The evidence does not show that the services provided by Fluor to TXU Gas were satisfactory to TXU.

965 Tr. Vol. 2 at 101 (Jan. 27, 2004).
966 Tr. Vol. 2 at 101-102 (Jan. 27, 2004).
967 Tr. Vol. 2 at 104 (Jan. 27, 2004).
968 Tr. Vol. 2 at 103-104 (Jan. 27, 2004).
969 Tr. Vol. 2 at 106 (Jan. 27, 2004).
970 Tr. Vol. 2 at 106 (Jan. 27, 2004).

Merely stating that TXU paid amounts to Fluor is not probative of their reasonableness or necessity. Merely stating that the Commission's Rule contains a December 2005 deadline is not evidence of anything. Merely stating that the adjustments are reasonable and necessary and reflect expected costs for the period in which rates will be in effect is not probative.[971] TXU did not show that $881,499 was a reasonable and necessary expenses for general engineering, project management, and program management services provided by Fluor.[972] The evidence does not show that TXU made a prudent, reasonable, or necessary expenditure for the services of Fluor. TXU did not show that the services provided by Fluor would contribute to future activity in the pipeline integrity assessment project.

TXU stated that it will assess more pipe in 2003-2005 and therefore requested an adjustment. However, the Examiners find that TXU provided no evidence regarding the per-mile cost. The Examiners are unable to determine whether the per mile cost will increase, decrease, or remain constant at $13,577 for years 2003-2005. The Examiners find that the evidence provided by TXU does not show that future costs of pipeline assessment are known and measurable. TXU may become more efficient at integrity assessment; therefore, the costs may decrease. TXU may assess pipeline in environmental conditions that increases the per-mile cost. TXU may be likely to first assess its highest-risk pipe segments; therefore, TXU's costs may decrease over time. TXU provided no support for its assumption that the test year cost-per-mile is indicative of future cost-per-mile.

TXU stated that it received *five* bids for project management services for the 2003 pipeline integrity work, and decided to use TEPSCO because TEPSCO was then providing TXU with contract pipeline services and had enhanced familiarity with the TXU pipeline system. (Emphasis added.) The Examiners therefore recommend that the Commission disallow $881,499, the amount TXU Gas determined it spent in test year 2002 for Fluor Daniel Project Management,[973] from the expenses associated with this project.

The Examiners' second recommendation regarding Pipeline Integrity Testing is that the Commission deny TXU's proposed adjustments to both Pipeline and Distribution, because TXU did not meet its burden to prove that these amounts for future integrity testing costs are known and measurable. TXU's estimate that 2003, 2004, and 2005 integrity testing costs will increase by the requested amounts is insufficient to warrant an upward adjustment to its proposed expenses. It is not probative to state that future expenses associated with pipeline integrity testing will increase or that the future expenses are known and measurable. TXU failed to meet its burden of proof that its test year amounts should be adjusted upward.

TXU provided no probative evidence that it would increase the amount of miles assessed for Pipeline from 277 (test year) to 434 or 435 miles in years 2003, 2004, and 2005, and would increase miles assessed for Distribution from zero to 50 or 51 miles in years 2003, 2004, and 2005. TXU provided no evidence about how it would increase its inspection miles. TXU provided no probative evidence that, subsequent to the test year, it had managed to actually increase the miles assessed. Because of the lack of probative evidence presented, TXU failed to show that it will meet the Commission's 50 percent completion milestone for December 2005.

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[971] TXU Exhibit 17 at 10.
[972] Tr. Vol. 2 at 101 (Jan. 27, 2004).
[973] ACC Exhibit 20, RFI Response to ACC 1-118, Attachment 1, line 23.

The Examiners' recommendation regarding TXU's requested upward adjustment is consistent with the Commission's decision in GUD 9304 (SOAH Docket 455-02-2065), *Statement of Intent of TXU Lone Star Pipeline to Establish an Integrity and Safety Assessment for Recovery of Pipeline Integrity Assessment and Management Expenses and Class Location Changes*. In GUD 9304, the Commission found that it could not establish the incremental rate requested by TXU Lone Star Pipeline without establishing the utility's reasonable and necessary operating expenses and appropriate rate of return on its invested capital. In this proceeding, TXU failed to present credible, probative evidence that the proposed upward adjustment of test year expenses constitutes a known and measurable change to produce a reasonable and necessary operating expense. Therefore, it is reasonable that the Commission disallow the adjustment.

TXU did not rebut ACC's assertion that $7,970 in redundant verification costs should be disallowed. TXU's statement that additional efficiencies could not be gained because an integrated testing program between TXU Gas and TXU Fuel Co. is already in place is insufficient to overcome ACC's proof.

Therefore, the Examiners recommend that the Commission incorporate their recommendations and two of ACC's recommendations to calculate a new, reasonable O&M expense for integrity assessment, as follows.

For Pipeline, the test year costs of $3,763,720 should be reduced by $881,499 to eliminate the Fluor project management costs and further reduced by $7,970 for redundant verification costs to derive new test year amount of $2,874,252. Applying a 5 percent (or $43,713) reduction for project efficiencies results in $2,830,539 (or $2,830,539, rounded). The Examiners find that this is a reasonable amount for integrity assessment for the period in which the rates will be in effect. The Examiners do not recommend the Commission apply an upward adjustment for future, unknown cost increases, as proposed by TXU.

For Distribution, the Examiners recommend using the previously recommended disallowance to calculate a reasonable per-mile cost estimate of $10,211.18 ($2,830,539 ÷ 277.2 miles = $10,211.18). TXU should average inspection of 50.3 miles of Distribution pipe per year for the years 2003 - 2005. Therefore, the appropriate annual expense is $513,962.72 ($10,211.18 x 50.3 miles = $513,962.72). The Examiners recommend the Commission allow TXU to include $513,963 as the reasonable O&M integrity assessment expense for the period in which the rates will be in effect. The Examiners do not recommend the Commission apply an upward adjustment for future, unknown cost increases, as proposed by TXU.

13. Uncollectible Expense

NARUC described Uncollectible Account 904 an account that shall be charged with amounts sufficient to provide for losses from uncollectible utility revenues. Concurrent credits shall be made to account 144, Accumulated Provision for Uncollectible Accounts. Losses from uncollectible accounts shall be charged to Account 144.

In this Proposal for Decision, the section on TXU's proposed service agreement (SLA) starting at page 98 contains additional information relating to the issue of uncollectible accounts. The SLA provided that if actual uncollectible write-off performance is below a certain quarterly and annual target, TXU Energy is credited for the difference. If actual performance is above targets, TXU Gas is credited with 50 percent of the write-off difference.[974]

<u>TXU's Position</u>

TXU stated that the amounts recorded to NARUC Account 904 relating to uncollectible expense that is included in total operating and maintenance (O&M) expense are reasonable and necessary and reflect the normal ongoing costs of TXU Gas operations.[975] TXU stated that in test year 2002, a credit reduction to Uncollectible Accounts Expense in the amount of $963,459 was made.[976]

TXU criticized Dallas's approach regarding Uncollectible Expense. Dallas recommended the use of a three-year average consisting of the years 1999, 2000, and 2002.[977] TXU noticed that year 2001 was omitted. Dallas included year 2001 in other normalization proposed averages. Dallas removed 2001 from its calculation of Uncollectible Expense, claiming that it was an "outlier." TXU observed that Dallas presented no evidence to show that TXU's proposed Uncollectible Expense is unreasonable or unnecessary.[978]

TXU stated that Dallas ignored the facts that:

- the level of uncollectible expense has increased since 1999;
- TXU has taken steps to minimize the level of expense through the SLA; and
- utilizing a true continuous three-year average, and incorporating the SLA adjustment, produces an increase, not a decrease, in expense.[979]

TXU did not use a contiguous three year average 2000, 2001, and 2003. TXU stated that using a contiguous three year average would have been to the utility's benefit. Instead , TXU used a more conservative approach.[980] TXU argued that the conservative level of Uncollectible Expense is therefore reasonable and necessary, and reflects the utility's ongoing level of expense.[981]

<u>Dallas's Position</u>

TXU Gas included a total of $4,543,652 in its proposed revenue requirement for uncollectible expense ($4,019,755 Distribution + $523,897 Pipeline = $4,543,652). Dallas reported that the uncollectible expense requested by TXU for Distribution was $4,019,755.[982] TXU testified that the actual credit to TXU Gas under the SLA with respect to uncollectible write offs in 2002 was $963,459.[983] The total uncollectible expense for Pipeline for the test year was $523,897.[984] Dallas recommended reducing the Distribution expense by $565,939, resulting in a Distribution uncollectible expense of $3,453,816, based upon a three year average.

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[974] TXU Exhibit 16, attachment BMG-3 at 3 of 17; ACC Exhibit 4 at 18.
[975] TXU Exhibit 30 at 14-15.
[976] TXU Exhibit 16 at 14; TXU 17 at 19.
[977] TXU Exhibit 30 at 13.
[978] TXU Exhibit 30 at 13.
[979] TXU Exhibit 30 at 13.
[980] TXU Exhibit 30 at 13.
[981] TXU Initial Brief at 98-99.
[982] TXU Exhibit 61, Schedule G-2 (D), line 27.
[983] TXU Exhibit 16 at 14.
[984] TXU Exhibit 61, Schedule G-2 (P), line 76.

Dallas noted that expense categories can vary significantly from year to year and argued that ratemaking principles require expenses be normalized to reflect average levels of expenses that may occur on an annual basis in the future. Dallas stated that it based its three-year average on 1999, 2000, and 2002, excluding year 2001 because it was an unusual year.[985] The following table provides the annual uncollectible expenses.

ANNUAL UNCOLLECTIBLES[986]

	Distribution
1999	$2,779,531
2000	$3,569,827
2001	$13,656,773
2002	$4,019,755

Dallas averaged 1999, 2000, and test year 2002 to derive the average uncollectible level of $3,777,524. Then, Dallas applied the SLA adjustment of $323,708 to the average expense in accordance with the provisions of TXU's SLA with TXU Energy. The following table summarizes Dallas's calculations.

Summary Table: Dallas's Calculations for Annual Uncollectible Expenses[987]

	Distribution
1999	$2,779,531
2000	$3,569,827
2001	$13,656,773
2002	$4,983,214
3-year average of 1999, 2000, and 2002	$3,777,524
SLA adjustment[988]	($323,708)
3-year average	$3,453,816

Dallas argued that the 2001 uncollectible expense of $13,656,733 was excluded because unusually cold weather caused the expense level to be extraordinarily high. Dallas noted that TXU did not use the 2001 data when establishing the SLA normalized level of charges.[989] Dallas summarized its position that the test year level was not representative-- it was higher than other recent years. An average is an appropriate way to look at this expense. Both TXU and Dallas agree that 2001 data should not be used.[990]

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985 Dallas Initial Brief at 52.
986 Dallas Exhibit 1 at 37.
987 Dallas Exhibit 1 at 38.
988 Dallas Exhibit 1 at 38 citing TXU's supplemental response to ACC RFI 6-19 and to the SLA agreement.
989 Dallas Exhibit 1 at 38.
990 Dallas Reply Brief at 26.

For 2002, Dallas used $4,983,214 for the uncollectible expense instead of $4,019,755 for calendar year 2002. In accordance with the SLA agreement between Distribution and TXU Energy, a credit was applied to the 2002 level after uncollectible expense was calculated. There was no equivalent SLA reduction for prior years. Dallas calculated the three-year average on a consistent basis and then reduced the three-year average by the SLA uncollectible credit applicable during 2002 pursuant to the agreement.

ATM's Position

ATM stated that it supported Dallas's proposed adjustments to reduce injuries and damages expenses, legal fees, and uncollectible expenses.[991]

Examiners' Recommendation

The Examiners recommend the Commission approve the $565,939 reduction, resulting in a Distribution uncollectible expense of $3,453,816. TXU stated that it could have used a contiguous three-year average. TXU argued that the calculation would have been to the utility's benefit. Therefore, TXU used a more conservative approach. TXU also stated that the expense was reasonable and necessary and reflected the normal ongoing costs of TXU Gas operations. The Examiners find that the evidence and argument presented by TXU is not meaningful or probative. TXU failed to show that its request of $4,019,755 for Distribution uncollectible expense and $523,897 for Pipeline uncollectible expense is reasonable and necessary for the provision of gas utility. Dallas provided its calculation based on a three year average. Dallas used $2,779,531 (1999), $3,569,827 (2000), and $4,019,755 (2002) and omitted $13,656,773 (2001). TXU did not show that Dallas's approach was piecemeal ratemaking. The evidence shows that TXU also omitted the higher $13,656,773 value when it developed the values to be used in the SLA. The Examiners find that it is reasonable for Dallas to have used the three year average to normalize the expense. The Examiners also find that it is reasonable that Dallas omitted the use of year 2001 because the evidence shows that year 2001 is a greater amount than years 1999, 2000, and 2002 combined. Having considered the evidence, the Examiners find that it is reasonable for the Commission to approve Distribution uncollectible expense of $3,453,816. Dallas did not recommend adjustment to the Pipeline expense and the remaining record evidence does not support an adjustment. Therefore, the Examiners recommend the Commission approve TXU's request for Pipeline uncollectible expense of $523,897.

14. Injuries and Damages

NARUC account 925, Injuries and Damages, includes the cost of insurance or the cost of reserve accrual to protect the utility against injuries and damages claims of employees and others, settlement of injuries, and damages claims. It also includes the cost of labor and labor-related supplies and expenses incurred for injuries and damages activities. Reimbursements from insurance companies for expenses charged on account of injuries and damages and insurance dividends or refunds are credited to this account.[992]

TXU's Position

TXU offered that the amounts it recorded to NARUC Account 925 and that it adjusted on Schedules G-5.6(D) and G-5.6(P) are reasonable and necessary and reflective of the normal ongoing costs of TXU

[991] ATM Initial Brief at 56-57.

[992] From NARUC Uniform System of Accounts for Class A and Class B Gas Utilities.

Gas operations.[993] TXU included Injury and Damages expense in the amount of $6,302,621 for Distribution and $916,300 for Pipeline, because the amounts represent the actual expenses incurred during the test year, as adjusted for known and measurable changes.

TXU addressed Dallas's concerns regarding TXU's treatment of injuries and damages. TXU stated that Dallas ignored TXU's actual experience in the test-year and instead based its recommendation on a four-year average to normalize Injury and Damage Expense. TXU argued this was piecemeal ratemaking and is a violation of test-year-based ratemaking principles.[994]

Dallas used the same three year average used for the Uncollectibles Expense. TXU argued that a large component of its Injury and Damages expense resulted from the payment of insurance premiums to TXU Vermont. In 1999, TXU did not pay premiums to TXU Vermont due to sufficient loss reserves available at that time.[995] As a result, TXU Pipeline had a negative balance in expense for the entire year.[996] The year 1999 was an aberration and not indicative of the known and measurable level of premiums charged to TXU Distribution and TXU Pipeline on an ongoing basis.[997] Dallas's exclusion of data as an outlier is not applied consistently. Indeed, TXU observed that Dallas's normalization methodology is for the goal of producing a desired outcome of lower expense, regardless of whether a rational basis exists to support that outcome.[998] TXU argued that the level of Injury and Damages expense incurred in the test year and adjusted for increasing costs relative to increases in premiums is known and measurable.[999] These expenses are reasonable and necessary and representative of TXU's ongoing level of expenses. TXU argued that Dallas did not provide justification for use of the 1999 aberration. Dallas's recommendation to reduce Injury and Damages expense is therefore unsupportable and should be rejected.[1000]

Dallas's Position

Dallas argued that TXU's test year level of Injuries and Damages Expense was atypical and too high to be reasonably representative of a continuing level of expense. Dallas used a four-year average to recommend that the appropriate level is $4,082,183 for Distribution, and $481,987 for Pipeline, which are reductions of $2,220,438 and $434,318 respectively.[1001] Dallas used the four years because that was the information that was available. The following chart summarizes Dallas's presentation of the four years of data.

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993 TXU Exhibit 17 at 10-11; TXU Exhibit 30 at 14-15; TXU Exhibit 28 at 54-55; TXU Initial Brief at 92 (Mar. 8, 2004).

994 TXU Exhibit 28 at 54-55; TXU Exhibit 30 at 14-15; TXU Initial Brief at 92-93 (Mar. 8, 2004).

995 TXU Exhibit 28 at 55; TXU Exhibit 30 at 13.

996 TXU Exhibit 30 at 13.

997 TXU Exhibit 28 at 55.

998 TXU Exhibit 30 at 13.

999 TXU Exhibit 30 at 15.

1000 TXU Exhibit 28 at 55; TXU Initial Brief at 92-93 (Mar. 8, 2004); TXU Reply Brief at 71 (Mar. 17, 2004).

1001 Dallas Initial Brief at 52.

Summary Table:
Four Year Injuries and Damages Amounts

YEAR	DISTRIBUTION AMOUNT	PIPELINE AMOUNT
1999	$1,402,335	($263,796)
2000	$5,688,360	$780,899
2001	$2,935,417	$494,545
2002	$6,302,621	$916,300
4-yr. Average	$4,082,183	$481,987
Difference	$2,220,438	$434,313 [1002]

Dallas argued that this evidence shows that the amount in the Injuries and Damages account during the test year is not a representative value for use in the future. Dallas argued that TXU would not want the expense to be set on 1999 amounts as Dallas does not want expense to be set on 2002 amounts where the average value is so much different from the test year.[1003]

ATM's Position
ATM supported Dallas's recommendation of a reduction to Distribution in the amount of $2,220,438 and a reduction in the amount of Pipeline of $434,318, resulting in appropriate levels of $4,082,183 (Distribution) and $481,987 (Pipeline).[1004]

Examiners' Recommendation
The Examiners recommend that the Commission approve TXU's request for Injuries and Damages based upon test year levels of $6,302,621 for Distribution and $916,300 for Pipeline. The record shows that in 1999 TXU did not pay premiums to TXU Vermont due to sufficient loss reserves available at that time.[1005] The record shows that a component of TXU's Injury and Damages expense is its payment of insurance premiums to TXU Vermont. As a result, TXU had Injuries and Damages expense of $1,402,335 for Distribution and a negative $263,796 for Pipeline.[1006] The evidence shows that year 1999 was not indicative of the known and measurable level of premiums charged to TXU Distribution and TXU Pipeline on an ongoing basis.[1007] The Examiners find that it is reasonable for the Commission to approve Injuries and Damages expense of $6,302,621 for Distribution and $916,300 for Pipeline.

15. Merger Related Expenses

For discussion relating to merger-related expenses such as Other Post Employment Benefits (OPEB), 1997 and 1999 Enhanced Retirement Plan (ERP), and the 1999 Voluntary Severance Plan (VSP), please see the discussion relating to Amortization of Regulatory Assets, beginning on page 224. The Examiners recommended that, consistent with prior Commission ruling, TXU's request for merger-related expenses

1002 Dallas Exhibit 1 at 40.
1003 Dallas Initial Brief at 52 (Mar. 8, 2004); Dallas Reply Brief at (Mar. 17, 2004).
1004 ATM Initial at 56-57.
1005 TXU Exhibit 28 at 55; TXU Exhibit 30 at 13.
1006 TXU Exhibit 30 at 13.
1007 TXU Exhibit 28 at 55.

be denied.

16. Legal Expenses/Regulatory Expenses

Issue Summary
TXU requested the Commission approve $1,552,350 in lawsuit related expenses it booked to Account 923 for Distribution.[1008] Intervening parties recommended the Commission disallow $809,092 for legal and lawsuit fees; $537,634 for the Denton Franchise Fee lawsuit; $167,282 for the PG&E weighted average cost; and $104,176 relating to Poly 1 pipe.

TXU's Position
TXU argued that it incurred expenses associated with three Commission regulatory proceedings and two civil lawsuits as ongoing costs of its business operations.[1009] TXU argued that although the exact nature and issues change, civil and regulatory proceedings are realities of operating a gas utility and will occur in future years. TXU stated that the lawsuit-related expenses and costs for representation before the Commission are reasonable expenses that are recurring in nature and are properly included in the cost of service.[1010]

Dallas
Dallas recommended disallowing a total of $809,092 for legal and lawsuit fees, including $167,282 for the PG&E weighted average cost, $537,634 for the Denton Franchise Fee lawsuit, and $104,176 relating to Poly 1 pipe. Dallas argued that the $167,282 requested for the PG&E case relating to a contract dispute involving weighted average cost of gas was neither reasonable or necessary because the cost is non-recurring and TXU failed to demonstrate that a similar lawsuit will occur on an annual basis and because TXU withdrew from the case.[1011]

Dallas argued that the Commission should disallow $537,634 for the Denton Franchise Fee lawsuit because TXU failed to demonstrate that a similar lawsuit will occur on an annual basis, because the lawsuit settled, and as a part of the dismissal of the lawsuit, the utility agreed that none of the city's legal fees would be passed through to ratepayers.

As discussed previously in this proposal for decision, Dallas recommended that TXU's request for legal and lawsuit expenses related to the Poly 1 pipe issue be reduced by $104,176 because the expenses were non-recurring, were not reasonable, were not prudent, and were not justified.[1012]

ACC
ACC also argued that the City of Denton litigation expense, project 10920109, should be disallowed because the activity was completed and is non-recurring. Therefore, it would be inappropriate to continue to recover these expenses from ratepayers.[1013] ACC argued further that TXU did not rebut ACC's

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[1008] Dallas Exhibit 1 at 43.
[1009] TXU's Initial Brief at 94-95 (Mar. 8, 2004); TXU Exhibit 30 at 11.
[1010] TXU's Initial Brief at 95 (Mar. 8, 2004).
[1011] Dallas Exhibit 1 at 43.
[1012] Dallas Initial Brief at 45 (Mar. 8, 2004); Dallas 1 at 44.
[1013] ACC Exhibit 4 at 37.

recommendation to remove the City of Denton litigation costs; therefore, the Commission should adopt its recommendation.[1014]

ATM

ATM concurred with Dallas and ACC.[1015]

Examiners' Recommendation

The Examiners recommend the Commission deny TXU's request for $537,634 for the Denton Franchise Fee lawsuit, $167,282 for the PG&E weighted average cost , and $104,176 relating to Poly 1 pipe, totaling $809,092 in legal and lawsuit fees. The Examiners find the evidence shows that these were one-time legal expenses, rather than on-going legal expenses typically incurred in the regular course and conduct of gas utility business. The Examiners find TXU's arguments and evidence unpersuasive that the Commission should approve legal fees for the PG&E contract dispute when TXU failed to show that a similar lawsuit will occur on an annual basis. The Examiners found no evidence to rebut Dallas's argument that as a part of the dismissal of the lawsuit, the utility agreed that none of the city's legal fees would be passed through to ratepayers. The Examiners found no evidence or arguments put forth by TXU to be persuasive that TXU's customers should therefore pay for legal expenses relating to the Denton Franchise Fee lawsuit. As discussed in the Poly 1 pipe section of this proposal for decision, TXU sought $104,176 relating to Poly 1 pipe. The Examiners reaffirm their recommendation that the Commission should disallow TXU's requested recovery of $104,176 relating to Poly 1 pipe legal and lawsuit fees[1016] because the expenses were non-recurring and were not justified.[1017] It is inappropriate for TXU's current ratepayers to pay for location and replacement costs of the Poly 1 pipe when it was imprudent and unreasonable for the utility to have used the Poly 1 pipe in 1970 and 1971 and when it was unreasonable and imprudent of the utility not to have immediately located and replaced the defective pipe as soon as it became aware of the defects in 1971.

The Examiners found no evidence to support TXU's position that it should be reimbursed for amounts spent for legal or litigation fees relating to cases brought before the Commission, but for which the Commission granted no relief. If included as expenses or as legal fees for approval by the Commission, TXU should not recover amounts for GUD 9291 or GUD 9300.

17. Oncor Logo Labeling Expenses

TUC §39.051[1018] and PUC Rule 25.342[1019] required each Texas electric utility in transition towards a competitive retail electric market to separate its regulated utility activities from its customer energy services business activities. In other words, business separation was required between power generation, retail electric providers (REP), and the transmission and distribution company. On April 25, 2000, the

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[1014] ACC Initial Brief at 92.

[1015] ATM Initial Brief at 56 (Mar. 8, 2004).

[1016] Dallas Initial Brief (Mar. 8, 2004).

[1017] Dallas Initial Brief at 45 (Mar. 8, 2004); Dallas 1 at 44.

[1018] Public Utility Regulatory Act, TEX. UTIL. CODE ANN. §§11.001 - 64.158 (Vernon 1998 and Supp. 2004) (PURA).

[1019] 16 TEX. ADMIN. CODE §25.342.

PUC approved TXU's plan for business separation.[1020] TXU's retail electric provider became TXU Energy. TXU's wires company became Oncor Electric.

In the section of this PFD regarding affiliate transaction issues with TXU Business Services, the issue of Activity/Project 19650000, Vehicle Graphics Changeout, is discussed. That account is for expenses associated with development of a plan with implementation and staffing to convert vehicle graphics from TXU to Oncor. In that section, the Examiners found that the record evidence did not show that TXU's request for expenses associated with converting vehicle graphics from TXU to Oncor was a necessary and reasonable cost of gas utility service to be included in rates. Instead, the Examiners found that the conversion of vehicle graphics from TXU to Oncor is part of TXU's transition to electric restructuring. TXU's electric division retained the familiar "TXU" name. Regulated gas utility customers should not pay for costs created by TXU's business separation resulting from electric restructuring. The Examiners recommended that the Commission disallow TXU's request for Distribution cost of $2,709 and Pipeline's cost of $903 as a non-recoverable expense.

For similar reasons stated by the Examiners in the TXU Business Services section of this PFD, the Examiners recommend that the Commission approve Dallas and ACC's proposed adjustment of $340,955 for Distribution cost of service for expenses related to Oncor brand logos and signs.

TXU's Position

TXU stated that Oncor Electric provides certain essential services to TXU Gas, including meter reading and other services, that are common to both the electric and gas companies.[1021] Combined business support activities benefit both gas and electric customers through the elimination or reduction of costs associated with duplicate management, computer systems, and buildings/facilities. TXU argued that it is therefore appropriate to assign a portion of these charges to TXU Gas.[1022]

TXU stated that no intervening party challenged the stated benefits of the services provided by Oncor Electric to TXU Gas. TXU argued that TXU Gas saves approximately $1,000,000 from Oncor Electric's refinement of the meter reading service (MRS). TXU argued that Account 930.2 expenses relate to uniform and vehicle branding expenses that are directly related to the provision of the shared services by Oncor Electric, therefore, the Commission should not approve ACC and Dallas's recommendation for a $340,955 adjustment. These NARUC Account 930.2 expenses result from activities including the purchase of Oncor Group meter reader uniforms and the placement or replacement of logos on Oncor Group vehicles. TXU argued that as a recipient of the benefits of the services, TXU Gas should be assigned an appropriate amount of the expenses incurred. TXU argued that these are normal ongoing operating costs of TXU Gas.

TXU stated that meter reading activities are a shared service performed by Oncor Electric employees. Because Oncor Electric meter readers read both electric and gas meters, Oncor Electric meter readers are

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[1020] PUC Docket No. 21950, *Application of TXU Electric Company for Approval of Business Separation Plan Pursuant to Subst. R. 25.342*, Interim Order Approving Stipulation and Settlement Regarding Approval of Business Separation Plan (Apr. 25, 2000).

[1021] TXU Exhibit 30 at 9.

[1022] TXU Exhibit 30 at 9-10.

required to be physically present on the premises of both electric and gas customers each month.[1023] These employees wear Oncor uniforms, travel in Oncor vehicles, and work in Oncor facilities.[1024] TXU argued that because they perform services for both electric and gas customers, all costs and savings of the Oncor Electric meter reading operations are properly shared by electric and gas customers.[1025]

TXU stated that it did not manipulate the regulatory process as Dallas alleged. TXU could have made no changes to its 2002 meter reading cost assignment methodology and not reduced gas meter reading expense by approximately $1 million. TXU argued that rebranding costs associated with electric operations that do not provide services to TXU Gas were not allocated to TXU Gas; only a portion of the rebranding costs for meter reading, economic development and support, and other shared organizations were assigned to the TXU Gas.[1026] TXU argued that it is unreasonable and inequitable to provide TXU's gas customers with the benefits of these shared operations, but then disallow the costs incurred in providing such shared services.

TXU argued that costs included in Account 930.2 are not one time costs resulting from a corporate name change, as alleged by intervening parties. Rather, they represent ongoing costs associated with repairing or replacing damaged or worn uniforms, vehicle logos, and facility signs. It is unreasonable to assume that TXU Gas will not incur these types of charges in the future. The amounts recorded to NARUC Account 930.2 related to Oncor Electric Branding/Relabeling included in total O&M expense are reasonable and necessary and reflect normal ongoing costs of TXU Gas operations.

Dallas's Position
TXU's response to ACC RFI 18-03 included at least $340,955 for expenses relating to the electric restructuring process. This amount included approximately $144,000 for the purchase of uniforms, approximately $132,000 as TXU's proposed cost-of-service for changing the logo on trucks to the Oncor logo, and approximately $65,000 per year for building signs identifying the new Oncor logo.[1027] Dallas argued that these are not recurring costs. Building signs and new truck logos are not costs incurred every year. These costs were incurred during the first year of electric restructuring which happened to be the 2002 test year. Dallas argued TXU's requested expense should be reduced by $340,955 to comply with Commission recognized principle of regulatory consistency or recognition of necessary known and measurable changes.[1028] Dallas stated that this adjustment would reduce Distribution by approximately $7.2 million and Pipeline revenue requirements by approximately $1.8 million.[1029]

ACC's Position
ACC argued that the $340,955 included by TXU in its Distribution cost of service for expenses related to Oncor brand logos and signs should be rejected. ACC stated that these costs are not reasonable and necessary to provide gas service. Oncor was created as part of TXU's transition to competition for the benefit of TXU's electric operations. The Oncor name is for the benefit of TXU Corporation and,

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[1023] TXU Exhibit 30 at 9-10.
[1024] TXU Exhibit 30 at 9-10.
[1025] TXU Initial Brief at 93-94.
[1026] TXU Exhibit 30 at 9-10; TXU Initial Brief at 93-94.
[1027] Dallas Exhibit 1 at 46.
[1028] Dallas Exhibit 1 at 47.
[1029] Dallas Exhibit 1 at 46-47; Dallas Initial Brief at 44-45.

ultimately, its transition into electric competition. Rebranding costs necessitated by having a separate Oncor business unit to meet TXU Electric's obligations should not be borne by TXU Gas' captive ratepayers. Gas customers did not need a second company to provide their gas service and, therefore, should not be charged with the cost of maintaining the Oncor name.[1030]

ACC noted that in TXU's rebuttal testimony, services provided to TXU Gas by Oncor Electric were confused with the costs to create the Oncor organization. These services were provided to TXU Gas prior to the creation of Oncor. ACC stated that it did not dispute the provision of the services. ACC summarized that TXU created Oncor Electric for reasons unrelated to gas operations; therefore, gas customers should not have to pay costs to preserve the name of a company other than TXU Gas. This expense should be disallowed.[1031]

ATM's Position

ATM supported the recommendation by Dallas and by ACC to remove costs related to one-time, non-recurring changes in logos and signage, thereby reducing Distribution expenses by $340,955.[1032]

Examiners' Recommendation

The intervening parties did not dispute the shared service of meter reading. TXU's arguments are misplaced. The intervening parties challenged whether it is appropriate for gas utility customers to share in costs that would not have been incurred but for TXU's Business Separation Plan. TXU failed to prove that its request for expenses associated with converting vehicle graphics from TXU to Oncor, the purchase of new uniforms, or changing building signs to identify the new Oncor logo is a necessary and reasonable cost of gas utility service to be included in rates.

In 1999, the Texas Legislature recognized as part of the restructuring of the electric industry that a utility should be allowed to recover its regulatory assets.[1033] However, the statute does not provide that electric regulatory assets should be recovered from gas utility customers. The evidence does not show that these costs are reasonable and necessary for the provision of gas utility services.

TXU stated that these costs represent ongoing costs associated with repairing or replacing damaged or worn uniforms, vehicle logos, and facility signs. The Examiners find no probative evidence showing that these expenses would have been incurred but for the change of the name of the utility due to electric restructuring activities. The record evidence does not show that building signs and new truck logos are yearly expenses. Record evidence does not show what the usual expense would be for purchasing new uniforms or for replacing worn uniforms in the usual course of business. No evidence was provided explaining why vehicle logos would have to be replaced. No probative evidence shows that building and facility signs would need to be modified in any way but for the change in name resulting from TXU's Business Separation Plan. The evidence shows that these costs were incurred during the first year of electric restructuring, which happened to be the 2002 test year. Having reviewed the evidence, the Examiners find that it is reasonable for the Commission to reduce TXU's requested Distribution expense

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1030 ACC Initial Brief at 139; ACC Reply Brief at 70.
1031 ACC Initial Brief at 139.
1032 ATM Initial Brief at 56.
1033 PURA §39.301.

by $340,955.

18. Affiliate Transaction Issues

For discussion and Examiners' recommendations relating to expenses and affiliated transaction issues, please see the discussion starting on page 46.

19. Depreciation

Depreciation is a component of the invested capital determination. In this proceeding, TXU's depreciation using equal life group (ELG) methodology, service lives, amortization of computer software, treatment of computer equipment, net salvage levels, and half-year construction are considered. TUC §102.152 requires utilities to carry a proper and adequate depreciation account. TUC §104.053(a)(1) provides that the adjusted value of invested capital is original cost, less depreciation. This section provides TXU's arguments on each of these issues and is then followed by the parties' responses.

TXU's Position

TXU requested the Commission approve depreciation expense for both Pipeline and Distribution. For Distribution, TXU used two general classes, or functional groups, of depreciable property: (1) the Distribution Plant property; and (2) General Plant property. The Distribution plant functional group consisted of service lines and associated facilities used to distribute gas within cities to TXU Gas customers. The general plant functional group contained facilities associated with the overall operation of the utility, such as office equipment and computers. TXU requested annual depreciation expense in the amount of $61,921,258 for its Distribution assets ($57,274,192 for Distribution plant functional group + $4,647,066 for the general plant functional group).[1034]

For Pipeline, TXU used five general classes, or functional groups, of depreciable property: (1) Gathering; (2) Transmission-Compressors; (3) Transmission-City Gate; (4) Underground Storage; and (5) General Plant. The gathering functional group consisted of smaller lines and associated facilities used to collect gas from wells. The Transmission-Compressors functional group includes facilities that are used to maintain adequate pressure throughout the System and to transport gas from the source of supply to the ultimate end-user or delivery point. The Transmission-City Gate functional group included larger pipelines and associated equipment, primarily used to transport gas from gathering and transmission systems to delivery points at the city gates and other large volume delivery points and interconnections. The Underground Storage functional group contained underground gas storage reservoirs and related equipment. The General Plant functional group contained facilities associated with the overall operation of the utility, such as office equipment and computers, rather than with a specific Transmission, Gathering, or Underground Storage classification. TXU requested annual depreciation expense in the amount of $15,689,774 for its Pipeline assets ($14,279,470 for the combined Transmission functional groups + $1,410,304 for the General functional group).[1035]

[1034] TXU Brief at 62 (Mar. 8, 2004); TXU Exhibit 14 at 10-11; TXU Exhibit 61, Schedule D-4(D).

[1035] TXU Brief at 62 (Mar. 8, 2004); TXU Exhibit 14 at 10-11; TXU Exhibit 61, Schedule D-4(P).

a. ELG Methodology

ELG Methodology: TXU used the ELG method to calculate depreciation, noting the Commission previously approved TXU's use of this method in GUDs 8664, 8976, and 9145-9148.[1036] TXU stated that no intervening party challenged TXU's use of the ELG method. TXU's service life calculation was described at TXU Exhibit 14, attachments DAW-2 (Distribution) and DAW-3 (Pipeline). TXU stated that no intervening party challenged TXU's proposed service life calculations. TXU countered Dallas's contentions that ELG provides the utility with a revenue advantage and accelerates the recovery of investment by stating that Dallas presented no evidence to support its position. TXU argued that ELG is a straight-line method of depreciation that ensures a more accurate recovery of its investment over the life of the assets. TXU argued that with respect to retirement mix, if historical retirement data are dismissed and only the current investment mix is considered, the net salvage percent would be more negative than the negative 40 percent TXU has requested here.[1037]

b. Service Lives/Lives of Less than Five Years

Remaining Life: TXU responded to Dallas's proposal regarding an adjustment to expense for accounts having a remaining life of less than five years. No intervening party challenged the service lives proposed by TXU regarding Distribution; however, Dallas proposed an adjustment to depreciation expense for three Pipeline gathering accounts having a remaining life of less than five years. TXU responded that it does not continue to book depreciation expense once an account is fully accrued argued and that (1) the utility cannot book more that 100 percent of its original investment as depreciation expense for an asset, (2) Generally Accepted Accounting Principles (GAAP) and 16 TEX. ADMIN CODE §7.5252(a) require assets be depreciated over the remaining service life of the asset rather than on an estimate of the time until the next rate filing, and (3) that no additional depreciation expense will be recovered to correct under-accrued accounts. TXU stated that the remaining lives for the three accounts at issue have remained relatively constant as a result of investment activity occurring between rate cases. Thus, it is inappropriate to assume that the utility will over-recover on accounts with a remaining life that will be completed before TXU's next full rate case.[1038]

c. Amortization of Software

Amortization of Software: TXU determined the appropriate amortization periods for intangible computer software, consistent with the expected useful life of the software, its underlying amortization rate, sound ratemaking policy, Generally Accepted Accounting Principles (GAAP), and the recognition of the increasing pace of technology improvements. Therefore, TXU argued, the proposed amortization periods for intangible computer software are appropriate. TXU did not agree with Dallas's proposal to extend software amortization lives to the period between rate proceedings. TXU referenced 16 TEX. ADMIN. CODE §7.5252(a) and GAAP, which require assets to be depreciated over their expected useful lives. TXU followed the American Institute of Certified Public Accountants Statement of Position 98-1. TXU stated

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[1036] TXU Brief at 63 (Mar. 8, 2004); TXU Exhibit 14 at 11-12.

[1037] TXU Exhibit 14 at 11-12; Tr. Vol. 3 at 136; TXU Reply Brief at 57 (Mar. 17, 2004).

[1038] TXU Exhibit 14, attachments DAW-2 at 29-30; TXU Exhibit 14, attachments DAW-3 at 37; TXU Exhibit 27 at 21-23; TXU Brief at 64 (Mar. 8, 2004); TXU Reply Brief at 60-61 (Mar. 17, 2004).

that it ceases accrual on an asset when the asset is either fully depreciated or fully amortized. TXU opposed Dallas's proposal to tie the amortization period to the time between rate proceedings[1039] and argued that its proposed amortization periods for intangible computer software should be adopted.

d. Miscellaneous Computer Equipment-Account 398

Miscellaneous Computer Equipment: Dallas recommended an adjustment to Account 398 (TXU Miscellaneous Computer Equipment), to exclude the depreciation expense from rate base. Dallas argued that because the booked depreciation expense for Account 398 is less than the amount granted in the utility's last rate case, any excess collected through rates should be used to reduce rate base and be refunded. TXU disagreed and responded that Dallas's position denies the utility recovery of the remaining investment in Account 398, even though the investment in the account is used and useful to gas utility customers. TXU argued Dallas's proposal would be retroactive ratemaking. TXU stated that it has a cumulative under-recovery of roughly $17.6 million in depreciation expense that it experienced since GUD 9145 was decided.[1040]

e. Net Salvage

Net Salvage: TXU argued that industry standards, municipal regulations, and removal costs have become increasingly expensive and requested the net salvage rate be adjusted from negative 30 percent to negative 40 percent for the Distribution function. Dallas recommended continuation of the existing negative 30 percent net salvage rate for the Distribution plant function. TXU stated in its March 17, 2004, Reply Brief that the negative 30 percent net salvage rate for the utility's Distribution function has been in place unchanged since 1995 and the natural gas industry as a whole is experiencing increasingly higher negative percentages of net salvage for Distribution plant.

TXU argued that its calculation of net salvage is appropriate because it used historical data, field experience, operations experience, and the same methodology approved by the Commission in GUD Nos. 8976 and 9145-9148 to calculate the rate. To ensure a more accurate representation of the asset characteristics in developing the depreciation study, TXU excluded outliers from the life and salvage analysis sales of plant facilities, inter-company transfers, and activity for capital projects where the utility received reimbursement for relocations from the life and net salvage analysis. TXU explained that it considered outliers to be data that does not fall within the normal distribution pattern of the sample data. These are considered to be anomalies because they deviate in excess of normal variation.[1041] TXU stated that the Poly 1 pipe removed as part of the safety compliance program (SCP) was considered to be an outlier and was excluded from both the life and net salvage analysis. TXU's policy to abandon facilities in place has existed since 1997; therefore, TXU reasoned, the historical data used to develop its proposed net salvage rate for the Distribution function reflected realistic removal costs. Similarly, any economies of scale currently realized were reflected in the historical net salvage data. TXU argued that the Edison Electric Institute (AGA/EEI) data was not the basis of its recommendation, but that the report

[1039] TXU Brief at 65 (Mar. 8, 2004); TXU Exhibit 27, attachment DAW-R-5.
[1040] Dallas Initial Brief at 54-55 (Mar. 8, 2004); TXU Initial Brief at 66-67 (Mar. 8, 2004); TXU Exhibit 27 at 23-24; TXU reply Brief at 61-62 (Mar. 17, 2004).
[1041] TXU Exhibit 14 at 13.

independently validates the reasonableness of its request.[1042]

f. Half Year Construction

Half-year Construction: TXU argued that ACC's half-year proposed adjustment was inappropriate; that reversal of vintage plant transfers excludes known and measurable changes in post test year plant; that exclusion of costs associated with computer software used solely for the benefit to TXU Gas customers is unreasonable; and that ACC's recommendations regarding the costs associated with the sale of the Streetman and Teague facilities are unfounded. TXU argued that its original cost of service at Exhibit 7, Schedule D-5(P) used an amortization rate of 17.99 percent for Account 303-Intangible Software (Pipeline computer software); however, TXU revised its schedules at TXU Exhibit 61, Schedule D-5(P), to use an amortization rate of 19.24 percent for this account. TXU argued that it fully supported the change to the depreciation rate for Pipeline computer software in its revised schedules in WP/D-4/3(P) of TXU Exhibits 61 and 67. TXU argued that, upon removal of this software investment, it recalculated the depreciation rate for Account 398 and the amortization rate for Account 303. The resulting depreciation rate for Account 398 went from 10.90 percent to 0.93 percent. The amortization rate for Account 303 went from 17.99 percent to 19.24 percent.[1043]

TXU argued that the evidentiary record in this proceeding supported a finding that TXU's requested depreciation expense for its Pipeline and Distribution assets were reasonable and that the requested amount should be approved by the Commission.

g. Construction Completed Not Classified (CCNC)

TXU requested to include post-test-year additional plant it referenced as construction completed not classified (CCNC). For discussion regarding CCNC, please see page 117. The Examiners recommended that post-test-year additions be disallowed; therefore, no decrepitation adjustment is needed for CCNC. However, if the Commission were to allow TXU to include CCNC, then the Examiners recommended that TXU be required to account for the associated depreciation amounts that were not included in its proposed rates.

h. Transfer or Relocation of Pipe

For discussion relating to depreciation relating to the transfer or relocation of pipe, please see this Proposal for Decision starting on page 130. The Examiners recommend that the Commission disallow from invested capital $55,660,675 relating to transfer and relocation of pipe. On an annual basis this means that return of $6,673,715 is disallowed and the associated depreciation of $1,942,558 is disallowed.

[1042] TXU Exhibit 13 at 10-11; TXU Exhibit 14 at 13; TXU Exhibit 27 at 16-19, 33-34 and 69; TXU Reply Brief at 57-60 (Mar. 17, 2004). Net salvage levels for Distribution functional groups were analyzed at TXU Exhibit 14, attachment DAW-2, Appendices E and F; Net salvage levels for Pipeline functional groups were analyzed at TXU Exhibit 14, attachment DAW-3, Appendices E and F; Tr. Vol. 3 at 143-144 and 156.

[1043] TXU Exhibit 7, Schedule D-5(P); TXU Exhibit 61, Schedule D-5(P); ACC Initial Brief at 14-20, 36-40, and 81; TXU Exhibits 61 and 67, Workpaper WP/D-4/3(P).

ACC

ACC recommended adjustments to depreciation expense that would reduce Distribution depreciation expense and increase Pipeline depreciation expense. ACC recommended reversal of vintage plant transfers made subsequent to the final Order in GUD 8976, and disallowance of post test year construction completed not classified (CCNC). Because the net impact reduced plant-in-service, ACC reduced depreciation expense by $1,456,153. ACC also removed additional amortization relating to Poly 1 pipe of $3,008,705. The total reduction ACC recommended to Distribution depreciation expense was $4,464,858.[1044]

For Pipeline, ACC recommended the Commission reverse vintage plant transfers, which impacted construction completed not classified (CCNC) and the Streetman and Teague sale proceeds. ACC's recommendations would increase Pipeline plant amounts. Therefore, ACC increased Pipeline depreciation expense by $259,392.[1045]

ACC proposed that the accumulated depreciation reserve be adjusted by half of the increase in annualized depreciation expense based upon the level of year-end plant-in-service (half year convention). For consistency with the test year depreciation expenses and the use of a year-end rate base,[1046] ACC proposed to adjust depreciation expense for only the incremental depreciation expense.[1047] ACC clarified that it was not recommending a half-year of depreciation expense subtracted from the net book value for calculation of a new rate base, as TXU understood. ACC recommended a half-year calculation to reduce total net Distribution plant-in-service by $2,834,316. The half-year adjustment to general plant reduced Distribution general plant by $15,277.[1048] Accumulated depreciation for Pipeline would be reduced by $393,342. ACC argued that its proposed half-year convention has been accepted by the Public Utility Commission.[1049]

The result would be a reduction to Pipeline accumulated reserve for depreciation of $217,615 and increasing net plant-in-service by the same amount. The adjustment to Pipeline general plant is a reduction of $175,817 due to the increase in proposed depreciation rates.[1050]

Dallas

Dallas agreed that no party opposed TXU's use of the ELG method; however, Dallas noted that use of ELG results in a greater amount of depreciation expense in current years than the ALG method. Dallas considered this to be a revenue advantage that allows TXU to accelerate the recovery of investment. Dallas recalled that the Commission had increased TXU's negative net salvage to 30 percent in GUD 9145. Dallas argued that, considering the accelerated recovery of investment, it is inappropriate for TXU to now request the Commission increase its net salvage from negative 30 percent to negative 40 percent. Dallas also argued that the increase in negative net salvage is impacted by the 2001 - 2002 accelerated Poly 1 pipe removal costs. Dallas identified four depreciation issues: (1) Distribution net salvage; (2) software amortization; (3) Account 398-Depreciation; and (4) a five-year remaining life for Pipeline plant.

1044 ACC Initial Brief at 80; ACC Exhibit 3A, attachment CTC-7.
1045 ACC Initial Brief at 81; ACC Exhibit 3A, attachment CTC-9.
1046 ACC Exhibit 3 at 11.
1047 ACC Reply Brief at 19 (Mar. 17, 2004).
1048 ACC Exhibit 3 at 13.
1049 ACC Reply Brief at 20 (Mar. 17, 2004).
1050 ACC Initial Brief at 40; ACC Exhibit 101, attachment EB-4(P) at 2, lines 9-10.

Dallas argued that TXU's actual net salvage experience in the last three years does not warrant or substantiate TXU's request to increase the negative net salvage by 33 percent. Dallas argued that TXU's explanation -- that municipalities are passing more restrictive ordinances -- is not sufficient evidence to warrant the proposed increase. Dallas challenged TXU's position, stating that higher costs are for installation of new pipe rather than removal of old pipe, and that the installation was booked to plant-in-service. Dallas recommended the Commission approve the current negative 30 percent net salvage and order TXU to fully document and demonstrate the reasonableness and appropriateness of any proposed modification in a future rate case. Retaining the negative 30 percent net salvage results in a $5,131,121 decrease to TXU's requested Distribution depreciation expense.[1051]

Dallas took the position that additional labor used for Poly 1 pipe removal affected TXU's negative salvage calculation; that the study period regarding net salvage included time for which Poly 1 pipe labor increase was included; that ratepayers should not bear these additional Poly 1 pipe costs; that there are no data supporting TXU's presumption that municipalities' ordinances will increase future removal costs; that TXU's retirement mix during the test year was not typical of TXU's usual retirement mix and therefore overstated the negative salvage; allocation of replacement-cost activity overstates negative salvage; and smaller replacement jobs (i.e., the more targeted replacements described by TXU)[1052] inflated negative salvage.

Dallas observed that TXU relied on the same Edison Electric Institute (AGA/EEI) report the utility previously relied upon in GUD 9145 to propose 30 percent negative salvage; and that TXU presented no new data in this GUD 9400 proceeding.[1053] Dallas noted that TXU was not forthcoming with information in responses. The utility represented that salvage and cost of removal data were only available at the functional level for Distribution,[1054] but in its rebuttal testimony TXU provided functional level and account level information.[1055]

Dallas further argued that TXU's proposed amortization period of ten years for the graphical mapping system software and customer information system (CIS) was too short and would result in an over-recovery of the utility's investment. Dallas determined the software investments will be fully recovered before or shortly after the rates in GUD 9400 become effective and TXU is not likely to return to the Commission for a full rate review for five years due to Tex. Utility Code, §104.301, entitled Interim Adjustment for Changes in Investment, enacted by Senate Bill 1271 (Acts 2003, 78th Legislature (2003 R.S.), Ch. 938, §1, eff. September 1, 2003). Based upon the type of software, historical usage of other large software programs, and treatment by other regulatory commissions, Dallas proposed to extend the amortization period of TXU's software from ten years to fifteen years for TXU's two largest software investment programs. This would cause Distribution's amortization expense to decrease by $2,396,336 and Pipeline

[1051] Dallas Initial Brief at 50 (Mar. 8, 2004); Dallas Exhibit 1 at 64-76; Dallas Exhibit, attachment JP-5; Dallas Reply Brief at 15 (Mar. 8, 2004);
[1052] Cross Examination of TXU Watson, Tr. Vol.9 at 44-45.
[1053] Dallas Initial Brief at 52 (Mar. 8, 2004) citing to TXU Exhibit 52; Dallas reply Brief at 15.
[1054] Dallas Exhibit 7.
[1055] Dallas Initial Brief at 53 (Mar. 8, 2004); TXU Exhibit 27, attachment DAW-R-3; Tr. Vol. 9 46 -50 (Feb. 5, 2004).

amortization expense to decrease by $715,038.[1056]

Dallas recommended an adjustment to reduce depreciation expense by $1,501,422 for TXU's Account 398-Miscellaneous Computer Equipment. Dallas asserted that although TXU had made adjustments for other outlier data, it had failed to do so regarding Account 398. Dallas reported that in GUD 9145, the Commission granted TXU over $2 million of annual depreciation expense to recover less than $3 million of remaining unrecovered investment. But, following the GUD 9145 rate proceeding, TXU retired the majority of the investment in the 398 account. Dallas argued that TXU was granted over $6 million of depreciation expense since its last rate case, to recover less than $3 million. In this proceeding, Dallas argued that TXU's request for an additional one-half million dollars per year for further recovery of its unrecovered investment is not reasonable or supported by evidence. Dallas argued that GAAP requires a $1,501,422 reduction to Distribution depreciation expense and a $5,928,517 decrease to rate base.[1057]

Dallas further argued that TXU's depreciation process will allow the utility to over-recover for certain Pipeline accounts, and proposed the utility be required to extend its Pipeline remaining life for five years to prevent over-recovery. Dallas provided an example that in a previous docket TXU sought and the Commission granted a full year's depreciation expense for an item in plant that will be fully depreciated by November 2004. Thus, granting TXU's proposed request in this proceeding, without applying a reduction, will enable TXU to over-recover for the three to five years that the rates in GUD 9400 will be in effect.[1058] Dallas recommended use of a five-year remaining life for recovery. Dallas used the five-year period because provisions of SB1271 led Dallas to assume the next TXU full rate proceeding will not be for another five years. Dallas reported that the five year remaining life for Pipeline would result in an approximate $575,671 reduction to annual depreciation expense.[1059]

ATM

ATM supported Dallas's proposed reductions to Distribution depreciation and to Pipeline depreciation.[1060]

Examiners' Recommendation

With regard to TXU's use of ELG methodology, and calculations of remaining life, amortization of software, and miscellaneous computer equipment, the Examiners recommend the Commission approve TXU's depreciation requests. The Examiners find that the evidence supports a decrease to Distribution rate for computer software Account No. 303 to 13.6955 percent to reflect removal of Poly 1 initiative software from this account. The issue of Poly 1 pipe is discussed in this proposal for Decision starting at page ?. Otherwise, the Examiners recommend the Commission approve TXU's request with respect to the amortization of computer software.

The Examiners find that the evidence does not support TXU's request for a higher negative net salvage (from negative 30 percent to negative 40 percent). The Examiners recommend that ACC's proposed half-

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[1056] Dallas Exhibit 1 at 76-77 and 81-83; Dallas Exhibit 1, attachment JP-6; Dallas Initial Brief at 53-54; Dallas Reply Brief at 13 (Mar. 17, 2004); TXU Exhibit 61, WP/D-4/3(D); WP/D-4/3(P).

[1057] Dallas Exhibit 1 at 83-89; Dallas Exhibit 1, Schedule JP-7, lines 14 and 15; Dallas Initial Brief at 55 (Mar. 8, 2004); Dallas Reply Brief at 14 (Mar. 17, 2004).

[1058] Dallas Reply Brief at 13 (Mar. 17, 2004).

[1059] Dallas Exhibit 1 at 92-94; Dallas Initial Brief at 55 (Mar. 8, 2004).

[1060] ATM Initial Brief at 50; Dallas Exhibit 2 at 64-89; Dallas Exhibit 2, attachment DJL-14 at 3.

year adjustment be rejected. The Examiners find that ELG is a straight-line method of depreciation; approval of ELG methodology is consistent with prior Commission decisions regarding the TXU Gas utility.

The unknown, future time until TXU will return to the Commission for a full rate case does not overcome the requirements of Generally Accepted Accounting Principles (GAAP) and 16 TEX. ADMIN CODE § 7.5252(a), which require assets to be depreciated over their expected service lives. Thus, amortization of an asset is to be over the life of the asset rather than on an estimated time until the utility will return to the Commission for a full ratemaking proceeding. The evidence shows that TXU followed the American Institute of Certified Public Accountants Statement of Position 98-1 to propose amortization periods for intangible software. The evidence did not show that TXU used any treatment inconsistent with GAAP; that TXU will over-recover; or that TXU accrues additional amounts on an asset after it has been fully depreciated or fully amortized. GAAP requires an individual amortization period for each piece of software; therefore, the Examiners find that it is reasonable for different software accounts to have varying service lives. The evidence shows that TXU's amortization period for intangible software, service life calculation, and depreciation of computer equipment are reasonable.

The Examiners did not find ACC's half-year convention to be radical, as TXU suggested. However, the Examiners recommend the Commission reject ACC's proposed half-year adjustment in this proceeding because TXU properly calculated accumulated depreciation for its assets using the methodology previously approved in GUD Nos. 8664, 8976, and 9145-9148; and because the evidence presented by ACC was not probative that a half-year adjustment to TXU's depreciation reserve was necessary.

When net salvage is negative (i.e., cost of removal exceeds the salvage or scrap value), the effect is an increase to depreciation rates. TXU's position that the Commission should approve an increase in negative net salvage (from negative 30 percent to negative 40 percent) is not supported by TXU's statements regarding industry trend, increased removal costs, more restrictive municipal ordinances, more restrictive work hours, or requirements to repair streets from curb to curb.[1061] On this issue, TXU's evidence was not credible, material, or probative. Mr. Watson presented depreciation testimony on behalf of TXU. He stated that it was his responsibility to compile information into either capitalization or regulatory asset categories.[1062] Although Mr. Watson stated that he had reviewed the statute in preparation of testimony, Mr. Watson did not demonstrate a general working knowledge of the statutory requirements applicable to depreciation issues.[1063]

Mr. Watson testified that TXU had experienced a significant change in net salvage because of increased removal costs that were due to increasingly restrictive municipal ordinances. The Municipal ordinances related to right-of-way work, repair of facilities under streets, and replacement requirements for entire panels of asphalt.[1064] Mr. Watson's testimony assumed "significant" increased costs but failed to quantify the actual effect of claimed increased removal costs on net salvage resulting from municipal ordinance demands. For example, Mr. Watson did not provide evidence showing distinction between increased

[1061] Tr. Vol. 3 at 92-100 (Jan. 28, 2004).
[1062] Tr. Vol. 3 at 46-48 (Jan. 28, 2004).
[1063] Tr. Vol. 3 at 39-40 (Jan. 28, 2004).
[1064] TXU Exhibit 14 at 16.

removal costs and increased removal costs due to changes in municipal ordinance requirements.[1065]

Instead, Mr. Watson directed the Examiners' attention to his depreciation study at TXU Exhibit 14, DAW-2 at page 107 of 117, and made a blanket statement that the amounts were actual retirement, salvage, and removal costs all booked as removal costs. Mr. Watson noted that there was a trend of increased costs, but stated that TXU did not determine the level of how much increase was attributable to a specific cause.[1066] Mr. Watson stated that TXU's ". . . path was to look at what happens on the books and then try to verify, if you will, that what is happening is real and why. And so we didn't try to get to the level of how much is removal for this and that."[1067] The Examiners find that a proposed change to depreciation rates resulting in a $5 million increase to cost of service warrants a detailed investigation into the causes of this change. The Examiners find that TXU's proposal, based on historical data, actuarial analysis, consultation with field engineers, and consultation with operating personnel is not probative. TXU's proposed modification of the net salvage from negative 30 percent to negative 40 percent is not supported by the weight of the evidence, the depreciation study, changes in municipal ordinances, or industry trend. The Examiners' recommendation to disallow TXU's proposed modification and to retain a negative 30 percent net salvage level is consistent with the Commission decision memorialized in the November 20, 2000, Final Order in GUD 9145, Finding of Fact 117.

In the section of this proposal for decision relating to the Transfer of Facilities, the Examiners recommended the Commission approve TXU's proposed transfer of assets to classify the asset in accordance with the asset's actual use. Therefore, no adjustment to depreciation is necessary.

20. Amortization of Regulatory Assets

Amortization of Regulatory Assets

In accordance with the Statement of Financial Accounting Standards (SFAS), a utility is allowed to defer the recognition of regulatory costs that have a probable corresponding increase or decrease in future revenues. TXU sought approval to amortize several items, including:

(1) the transition obligation related to Other Post Employment Benefits (OPEBs);
(2) the 1997 Enhanced Retirement Plan (1997 ERP);
(3) the 1999 Early Retirement Plan (1999 ERP) and the 1999 Voluntary Severance Plan (1999 VSP);
(4) the Winning Innovative Services (WINS) Program; and
(5) the Safety Compliance Program (SCP).

TXU sought approval to include amortized expenses for these items considered to be regulatory assets. The regulatory asset amount and subsequent amortization treatments are summarized in the two tables that follow.[1068]

1065 Tr. Vol. 3 at 92-100 (Jan. 28, 2004).
1066 Tr. Vol. 3 at 98-99 (Jan. 28, 2004).
1067 Tr. Vol. 3 at 99, lines 3-7 (Jan. 28, 2004).
1068 ACC Exhibit 2 at 35.

Regulatory Asset	**Distribution**	**Pipeline**
1997 ERP	16,175,827	0
OPEB - Transition Obligation	12,259,711	2,706,514
1999 Early Retirement Program (ERP)	2,171,687	819,157
1999 Voluntary Service Program (VSP)	967,095	52,695
WINS - TXU Business Services	878,146	565,216
WINS - Oncor Electric	4,682,337	1,609,258
Total	$37,134,803	$ 5,752,840

Regulatory Asset Amortization	**Distribution**	**Pipeline**
1997 ERP	1,672,036	0
OPEB - Transition Obligation	1,225,971[1069]	270,653[1070]
1999 Early Retirement Program (ERP)	246,837	67,386[1071]
1999 Voluntary Service Program (VSP)	108,459	4,335[1072]
WINS - TXU Business Services	175,629	113,043
WINS - Oncor Electric	936,467	321,852
Total	$ 4,365,399	$ 777,269

a. SFAS 106 OPEB Transition Obligation

TXU's Position

TXU explained that Other Post Employment Benefits or OPEBs refers to all forms of post employments or post retirement benefits, other than pensions, expected to be provided by TXU in the future to employees and retirees. SFAS 106 provides that OPEB costs should be recognized by the utility during the employee's employment period because they represent an obligation to provide future benefits. OPEB transition obligation is the liability the utility recognized when the utility adopted SFAS 106 in 1993. TXU argued that the merger between ENSERCH and TXU Corp. caused the utility to actually incur the OPEB transition liability.[1073]

TXU acknowledged that in GUD 9145, the Commission disallowed the OPEB transition obligation. However, the utility argued that the Commission disallowed the amount because the utility mistakenly

[1069] ACC Exhibit 2, Schedule GWT-23.
[1070] ACC Exhibit 2, Schedule GWT-25.
[1071] 1999 ERP + 1999 VSP = $71,720.25; TXU Exhibit 7, Schedule G-5.12(P).
[1072] TXU Exhibit 7, Schedule G-5.12(P)).
[1073] TXU Initial Brief at 70-72 (Mar. 8, 2004).

identified the amount as a merger-related cost. Therefore, TXU reasoned, the Commission would reconsider the transition obligation at this time. At the time of the Commission's decision in GUD 9145, TXU continued to amortize the OPEB regulatory asset. TXU argued that the OPEB transition obligation was not a merger related cost but arose as a result of the adoption of SFAS 106 in 1993; that amortization of that transition obligation has been approved by the Commission; and it is reasonable to include transition obligation amortization expense in this proceeding.[1074]

Dallas's Position
Because TXU made the classification in GUD 9145 and received an adverse ruling from the Commission, Dallas argued that the utility should be bound by that ruling. Dallas argued that the items contemplated in GUD 9145, OPEB, and ERP or VSP, were litigated and should require no further discussion in this proceeding.[1075]

ACC's Position
ACC stated that SFAS 106 defines the transition obligation as the unfunded and unrecognized accumulated post-retirement benefit obligation for all plan participants at the date SFAS 106 was adopted by a company. The accepted amortization in the utility industry is 20 years, as TXU requested. TXU reported these same amounts as merger related costs in GUD 9145, which were disallowed by the Commission. ACC reported that if these costs were mistakenly identified as merger-related costs, the utility never corrected the error.

ACC also argued that the Examiner in GUD 9145 made it clear that the decision was based upon the fact that the costs were non-recurring, rather than whether these were merger related. In response to TXU's assertion that it has received rate relief from 99.95 percent of its Distribution customers,[1076] ACC noted that there is no specific approval of the amortization expense. Instead, ACC argued it is not possible to determine whether any amount for the regulatory asset amortization was actually approved.[1077]

ACC argued that these items were included in TXU's request in GUD 9145, were appropriately denied by the Commission, and TXU should not get a second attempt.[1078] ACC stated that the only merger related costs in GUD 9145 were the OPEB transition obligation and the 1997 ERP; the Commission's disallowance was based on both their merger related character and because these costs were non-recurring.[1079]

ATM's Position
ATM opposed the inclusion of the OPEB transition obligation costs, stating that the costs were disallowed in GUD 9145.[1080]

Examiners' Recommendation
The Commission previously denied TXU this amortization request; the Examiners find that the

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[1074] TXU Initial Brief at 72 (Mar. 8, 2004).
[1075] Dallas Reply Brief (Mar. 17, 2004).
[1076] ACC Exhibit 2 at 38 and attachment GWT-25 at 1.
[1077] ACC Exhibit 2 at 35-40.
[1078] ACC Initial Brief at 86-87.
[1079] ACC Reply Brief at 66-67.
[1080] ATM Initial Brief at 50-51.

Commission determination in GUD 9145 should stand. TXU should not be given an opportunity to relitigate prior decisions that were adverse to its position. TXU should have made appropriate arguments at the time of GUD 9145, rather than waiting until this proceeding to try to rectify its possible mis-characterization of the expense as merger related.

Further, the Examiners have studied all the evidence. The Examiners find that rates should not be based upon atypical, non-recurring costs that pertain to prior periods. Instead, rates in this proceeding should be based on test year 2002 level of expenses adjusted for known and measurable changes. TXU failed to show that the requested amounts for amortization of expenses were related to the utility's 2002 test year amounts. TXU attempted to explain that it made a mistake in how it characterized the amounts requested in GUD 9145, but failed to provide sufficient, persuasive evidence that its request to recover this expense in GUD 9400 is reasonable and necessary. Therefore, the Examiners find that it is reasonable for the Commission to disallow OPEB amounts and to preclude TXU from bringing this expense forward yet another time.

b. 1997 Enhanced Retirement Plan (1997 ERP)

The 1997 Enhanced Retirement Plan (1997 ERP) was created after the merger between ENSERCH and TXU Corp. as a cost reduction, when an early retirement plan was offered to employees. Approximately 153 TXU Gas Distribution employees retired early. TXU sought approval to include as an amortized expense the amounts for the 1997 ERP.

TXU's Position

The utility argued that these were not merger costs because they were not costs incurred in the merger. TXU stated that it could have achieved the merger without offering any retirement plan, but chose to offer a plan because employee reductions would reduce future costs of serving customers, therefore benefitting gas customers. TXU considered this to be the same as offering an early retirement plan independent of any merger, as in 1999. The purpose of the 1997 ERP was to reduce payroll and related employee benefit costs. TXU argued that it incurred liability costs associated with the 1997 ERP, and deferred the costs into a regulatory asset.[1081]

TXU argued that in GUD 9145, it inadvertently combined 1997 ERP costs with the OPEB transition costs and mistakenly classified the costs as merger related. TXU argued that the costs are actually on-going costs of doing business and should therefore be included in rates.[1082]

TXU countered ACC's and Dallas's arguments that these were merger related costs by stating that although the 1997 ERP costs were incurred in order for the utility to achieve savings, the costs were not costs to achieve the merger and were not necessary to make the merger a success. TXU countered Dallas's assertion that the costs are not recurring by stating that cost reduction programs involving employee severance are recurring. TXU argued that the nature of a regulatory asset amortization recognizes that it is appropriate to defer some types of costs for recovery over time.[1083]

[1081] TXU Initial Brief at 73-75 (Mar. 8, 2004).
[1082] TXU Initial Brief at 74 (Mar. 8, 2004).
[1083] TXU Initial Brief at 75-76 (Mar. 8, 2004).

TXU also argued that, in accordance with the requirements of SFAS 71, to create a regulatory asset, it is probable that future revenue in an amount at least equal to the capitalized cost will result from including that cost in allowable costs for ratemaking purposes. TXU stated that it correctly believed that the Commission would allow the utility to recover ERP costs in rates because if the utility had correctly classified the expenses in GUD 9145, they would have been approved.

ACC's Position

ACC's arguments were similar to those it expressed relating to the OPEB transition obligation costs, discussed above. ACC argued that these items were included in TXU's request in GUD 9145, were appropriately denied by the Commission, and TXU should not get a second attempt.[1084] ACC stated that the only merger related costs in GUD 9145 were the OPEB transition obligation and the 1997 ERP; the Commission's disallowance was based on both their merger related character and that these costs were non-recurring.[1085]

ACC noted that the U.S. Securities and Exchange Commission filing, Form U-1, filed by the TUC Holding Company on November 6, 1996, stated that among other things, the mergers [of TUC and ENSERCH] are also expected to create significant operational and administrative economies and efficiencies through combined meter reading, meter testing and billing operations as well as customer service operations, savings in facility maintenance and emergency work coordination, and other administrative and general savings. ACC recalled that in GUD 8976, the Examiner discussed the sources and quantification of merger savings and determined that the savings were the result of employee reductions identified and recognized in the merger transaction.[1086]

ACC also noted that the 1997 ERP costs were not costs to achieve the merger, but were incurred to achieve the merger savings. ACC reflected upon TXU's statement that the purpose of the 1997 ERP was to reduce payroll and related employee benefit costs, and declared that is exactly what "merger-related savings" means. ACC recommended that the Commission's decision in GUD 9145 should be followed in this proceeding to disallow 1997 ERP costs.[1087]

Dallas's Position

Dallas argued that TXU simply renamed the costs and now seeks a second request for rate treatment. Dallas noted that these ERP and VSP costs are the same merger costs that were previously denied by the Commission in GUD 9145 as TU/ENSERCH costs relating to the retirement and severance costs in 1999. Dallas realized that in GUD 9145, TXU had made the same arguments it now makes regarding other agencies' approvals of similar costs. Dallas recommended that the Commission affirm its prior decision and disallow these costs. Dallas argued further that rates should not be based upon atypical, non-recurring costs that pertain to prior periods. Instead, rates should be based on test year 2002 level of expenses adjusted for known and measurable changes. Dallas asserted that these are indeed merger related costs that did not occur in the test year. Dallas concluded its argument that the Commission should deny the amounts as expense and should deny TXU's requests for amortization.[1088]

[1084] ACC Initial Brief at 86-87.
[1085] ACC Reply Brief at 66-67.
[1086] ACC Exhibit 2 at 40; ACC Exhibit 2, attachment GWT-28; ACC Exhibit 2, attachment GWT-19.
[1087] ACC Reply Brief at 66-67.
[1088] Dallas Exhibit 1 at 41-43.

ATM's Position

ATM noted that in TXU's March 8, 2004, Initial Brief, TXU stated that the purpose of the 1997 ERP was to reduce payroll and related employee costs to take advantage of the synergies associated with the merger. ATM argued that this is a clear admission by TXU that the ERP was merger related. ATM argued that similar to events that were reviewed by the Commission in GUD 8976,[1089] downsizing occurred as a result of the merger; shareholders have enjoyed the merger savings from the moment the ERP was in place. TXU did not immediately defer these savings to ratepayers. Therefore, it is unfair to now charge ratepayers seven years after the merger for the costs of the ERP when ratepayers have not had the benefit of the savings, as did the shareholders.[1090]

Examiners' Recommendation

The Commission previously denied TXU this amortization request for 1997 Enhanced Retirement Plan (1997 ERP) expense; the Examiners find that the Commission determination in GUD 9145 should stand. TXU should not be given an opportunity to relitigate prior decisions that were adverse to its position. TXU should have made appropriate arguments at the time of GUD 9145, rather than waiting until this proceeding to try to rectify its possible mis-characterization of the expense as merger related.

The Examiners reject TXU's position[1091] that in a settled case, in the absence of a specific finding disallowing a cost of service item, the cost is considered to be approved and any shortfall from the requested increase is considered to be a reduction to the return allowed on common equity. Rather, settlements are generally made through a negotiated process that results in numbers that are reasonable and are acceptable to all involved parties. The Examiners are not aware of any authority for TXU's blanket assumption and note that TXU failed to provide citation to such authority to support its position.

The Examiners have studied all the evidence. The Examiners find that these are merger related costs. Further, the Examiners find that rates should not be based upon atypical, non-recurring costs that pertain to prior periods. Instead, rates in this proceeding should be based on test year 2002 level of expenses adjusted for known and measurable changes. TXU failed to show that the requested amounts for amortization of expenses were related to the utility's 2002 test year amounts. TXU attempted to explain that these costs for 1997 ERP were inadvertently combined with OPEB amounts and mistakenly referenced as merger costs in the GUD 9145 proceedings; however, TXU failed to provide sufficient, persuasive evidence that its request to recover this expense in GUD 9400 is reasonable and necessary. Therefore, the Examiners find that it is reasonable for the Commission to disallow 1997 ERP amounts and to preclude TXU from bringing this expense forward yet another time.

c. 1999 ERP and 1999 VSP

In 1999 TXU offered an early retirement plan (ERP) similar to the 1997 ERP, discussed in the previous section. To reduce salaries, costs, and labor, ERP 1999 was initiated to provided an opportunity for TXU employees to retire. A total of fifteen Distribution employees and ten Pipeline employees accepted the

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[1089] ATM Initial Brief at 34 (Mar. 8, 2004), citing to Finding of Fact 37 in GUD 8976, *Statement of Intent to Change the City-Gate rate of TXU Lone Star Pipeline* (Jun. 26, 2000).

[1090] ATM Exhibit 1 at 41; ATM Initial Brief at 51 (Mar. 8, 2004); ATM Reply Brief at 34 (Mar. 17, 2004).

[1091] TXU Exhibit 31 at 10.

early retirement offer. In an effort to encourage employees who were not otherwise eligible for the 1999 ERP to leave TXU, the utility developed the 1999 voluntary severance plan (VSP). Four Distribution employees accepted the voluntary severance offer.[1092]

TXU's Position

TXU argued that it incurred liability costs associated with the 1999 ERP and 1999 VSP, and deferred the costs into a regulatory asset. TXU also argued that, in accordance with the requirements of SFAS 71, to create a regulatory asset, it is probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for ratemaking purposes. TXU stated that it correctly believed that the Commission would allow the utility to recover ERP costs in rates because, if the utility had correctly classified the expenses in GUD 9145, they would have been approved.[1093] TXU proposed to amortize these costs over twelve years, based on the average remaining service life of those employees that elected to accept the 1999 packages.

Dallas's Position

Dallas recommended that the Commission disallow TXU's requested expenses for the ERP or VRP. Dallas recommended TXU's requested expenses be reduced by $2,927,332 Distribution and $71,721 Pipeline for the claimed Enhanced Retirement Plan or Voluntary Severance Plan, and $1,225,971 Distribution and $270,631 Pipeline for what is now claimed to be transition obligation.[1094]

ATM's Position

ATM opposed TXU's inclusion of costs for 1999 ERP and 1999 VSP because these costs were incurred approximately five years ago. ATM argued that the utility has benefitted from the savings of these programs through the reduction of employee levels. ATM stated that TXU has proposed no adjustment to defer and refund prior cost savings to ratepayers; therefore, it would be improper to recognize prior expenses without recognizing prior cost savings. ATM argued that it would be inconsistent and improper to allow the utility to defer expenses from 1999 while the related cost savings have been passed to stockholders.[1095]

Examiners' Recommendation

In TXU Exhibit 18 at 17; TXU Exhibit 31 at 11; TXU's March 8, 2004, Initial Brief; and TXU's March 17, 2004, Reply Brief, TXU stated that in GUD 9145, the Commission allowed recovery of the costs for 1999 ERP and 1999 VSP and that the 1999 ERP and 1999 VSP savings were reflected in the GUD 9145 rates. TXU failed to cite to the Commission's final Order or the PFD in GUD 9145 to support its position.

Even if the Intervening Parties were wrong as to the facts of GUD 9145, the Examiners find that it is TXU's burden to show that the requested amortization is reasonable and necessary. The Examiners find that TXU failed to meet that burden because there is a lack of evidence to support TXU's request.

[1092] TXU Exhibit 18 at 16-18; TXU Initial Brief at 76.
[1093] TXU Exhibit 18 at 17; TXU Initial Brief at 76.
[1094] Dallas Exhibit 1 at 42; Dallas Initial Brief at 44-45; Dallas Reply Brief at 16-17 (Mar. 17, 2004).
[1095] ATM Initial Brief at 53 (Mar. 8, 2004).

The Examiners find that rates should not be based upon atypical, non-recurring costs that pertain to prior periods. Instead, rates in this proceeding should be based on test year 2002 level of expenses adjusted for known and measurable changes. TXU failed to show that the requested amounts for amortization of expenses were reasonable or necessary.

d. WINS

The WINS program started out as Worldwide Innovative Services, but as TXU's European operations were discontinued, the name changed to Winning Innovative Services.[1096] WINS is discussed thoroughly in a dedicated WINS Section. In this section regarding TXU's request for amortization of expense relating to WINS, the Examiners affirm their two recommendations regarding WINS. First, the Examiners recommend the Commission deny TXU's request for inclusion of WINS costs in the rates for TXU Gas customers. Second, the Examiners recommend the Commission approve TXU's proposal to include in rates WINS savings; however, the Examiners recommend increasing the amount of WINS savings, consistent with Dallas's recommendation.

Examiners' Recommendation
WINS is throughly discussed in this Proposal for Decision starting on page 34. Consistent with earlier discussion, the Examiners recommend the Commission disallow TXU's request to amortize WINS expense.

e. Poly 1 Pipe/ Safety Compliance Program (SCP) Expenses

The Poly 1 pipe / Safety Compliance Program (SCP) issues are discussed in this Proposal for Discussion starting at page 13. In this section regarding TXU's request for amortization of expense relating to the Poly 1 pipe program or SCP expense, the Examiners affirm their recommendation.

Because TXU failed to provide sufficient evidence showing that the expenses were prudently incurred, the Examiners find that TXU is not entitled to recover through rates paid by its customers the amounts it expended relating to Poly 1 pipe. Having considered all parties' arguments relating to the Poly 1 pipe safety compliance program (SCP) issues, the Examiners recommend that with regard to Poly 1 pipe expenses, the Commission Order TXU to immediately cease recovery of any amounts previously approved relating to Poly 1 pipe or the Safety Compliance Program; deny TXU's request for a return on any Poly 1 pipe expenses; deny TXU's request for $104,176 in legal fees; preclude TXU from all future recovery of the expenses capitalized as gas utility plant-in-service; preclude TXU from all future recovery of the expenses for its Safety Compliance Program; and preclude TXU from any future request for reimbursement of location or replacement of Poly 1 pipe as a Safety Compliance Program or under any other program from the Commission or through capital investment adjustment factor (CIAF) in accordance with TUC §104.301 (SB 1271, 78th Reg. Leg. Session).

Examiners' Recommendation
Consistent with their comprehensive analysis of the Poly 1 pipe program or SCP expense, the Examiners recommend the Commission disallow TXU's request to amortize SCP or Poly 1 pipe costs; deny TXU's

[1096] Staff Initial Brief at 4 (Mar. 8, 2004); ACC Exhibit 2 at 41a.

request to amortize the costs of the Safety Compliance Program over fifteen years, forty years, or any other time period; and deny TXU's request to have the unamortized amounts of the SCP regulatory asset be included in rate base.

IX. Gas Cost Recovery and Lost and Unaccounted for Gas

A. Lost and Unaccounted for Gas

TXU's Position

Mr. Gary Goble testified that the lost and unaccounted for gas percentage for the distribution system for the twelve months ending June 30, 2002 was 2.59%.[1097] Mr. Goble testified that 16 Tex. Admin. Code §7.5525 requires that LUG be based on the most recent annual period ending June 30.[1098] Mr. Goble also testified that the retention factor for the pipeline system is 1%. Mr. Goble further testified that the retention factor is the percentage of customer supplied gas retained in the pipeline in order to use for company operations.[1099] Mr. Goble testified that the primary use of retention gas is to provide replacement gas for lost and unaccounted for gas in the pipeline.[1100]

Railroad Commission Staff's Position

Staff argues that 16 Tex. Admin. Code §7.5525 requires LUG to be limited to a maximum of 5% or actual, not to exceed 5%. Staff also argues that known and measurable gas volumes that are not company used gas should not be included in the calculation of LUG.[1101]

Allied Coalition of Cities' Position

Mr. McMorries testified on behalf of ACC that it appeared "that the volumes of gas sold to the Residential and Commercial customers were not corrected to the 14.65 psi base before deducting these volumes from the total gas entering the system to determine the LUG factor."[1102] As a result, Mr. McMorries testified that there is a net over-recovery of $1,557,203. ACC proposes setting LUG for the Distribution system "at a maximum of 2.00%, which represents a five year average of experienced gas losses since recent year losses do not appear representative of TXU historical experience."[1103]

ACC also proposes increasing TXU's lost and unaccounted for gas amount by 402,077 Mcf due to net over-recovery of gas costs and corresponding understatement of gas loss.[1104] Mr. McMorries testified that the "objective of the gas cost adjustment clause should be to recover only costs of gas, not profit or operating expenses, and to recover that cost in a reasonably accurate and non-discriminatory manner."[1105]

[1097] TXU Exhibit 24 at 11.
[1098] TXU Exhibit 24 at 12.
[1099] TXU Exhibit 24 at 12.
[1100] TXU Exhibit 24 at 12.
[1101] Staff Closing Argument at 6.
[1102] ACC Exhibit 224 at 27.
[1103] ACC Exhibit 224 at 27.
[1104] ACC Exhibit 224 at 16-17.
[1105] ACC Exhibit 224 at 19.

Industrial Gas Users' Position
IGU's position is that TXU's proposed LUG factor is unreasonable and should be reduced.[1106] IGU proposes that the Commission reduce TXU's LUG factor and that LUG be based on the three-year average of LUG percentages for the years 2000-2002.[1107] IGU recommends the Commission adopt the three-year average for Pipeline of 0.82% and 1.72% for Distribution.[1108]

Examiners' Recommendation
TXU has proposed for the first time that actual LUG be recovered as gas cost. Given that actual LUG will be recovered, the Examiners agree with Staff's position that a 5 percent cap on LUG be adopted. The Examiners find this to be a reasonable proposal to limit any atypical result that may occur as a result of the utility recovering actual LUG through gas cost. Therefore the Examiners recommend that LUG be capped at 5 percent.

The parties objected to TXU's LUG factor as too high. Further objection was made to the calculation of LUG on a system-wide basis. The weight of the evidence indicates that LUG was determined correctly. The evidence indicates that determining LUG for the entire TXU system is more accurate than determining LUG at the municipal level. Given that system-wide rates are being sought in this case, it is reasonable and appropriate to determine LUG on a system-wide basis. The evidence does not establish that the test year data is atypical and should be rejected. Further, the evidence submitted did not establish by a preponderance of the evidence that a period other than the annual period ending June 30 should be used. Therefore the Examiners find that TXU's proposed LUG factor is just and reasonable and recommend adoption by the Commission.

B. Gas Cost Recovery

TXU's Position
TXU has proposed Rider GCR – Gas Cost Recovery ("Rider GCR"), as a mechanism for recovering TXU's costs for gas sales made to residential, commercial and industrial customers.[1109] Alan D. Anderson, Ph.D., provided testimony on behalf of TXU regarding its proposed gas cost recovery mechanism.[1110] Dr. Anderson testified that there are three elements to the gas cost recovery mechanism: (1) the monthly Gas Cost Recovery Factor; (2) the annual reconciliation of amounts billed for gas with the costs incurred for gas; and (3) an annual review of TXU's gas purchases.[1111]

Rider GCR determines the amount due for gas cost recovery by multiplying the Gas Cost Recovery Factor (GCRF) by the customer's monthly volume.[1112] The GCRF is determined by adding the Estimated Gas Cost Factor (EGCF), Reconciliation Factor (RF), Taxes and Adjustments.[1113] TXU proposes submitting

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[1106] IGU Initial Brief at 5-7.
[1107] IGU Initial Brief at 5-7.
[1108] IGU Initial Brief at 5-7.
[1109] TXU Exhibit 4 at 25.
[1110] TXU Exhibits 25 and 38.
[1111] TXU Exhibits 25 at 3.
[1112] TXU Exhibit 4 at 25.
[1113] TXU Exhibit 4 at 25.

a quarterly filing to the Commission showing each element of the GCRF and the total GCRF.[1114] The EGCF is the estimated cost of gas divided by the total gas sales to residential, commercial and industrial customers.[1115] TXU has proposed including lost and unaccounted for gas attributed to residential, commercial and industrial customers and the reconciled balance of unrecovered gas costs in the determination of the EGCF.[1116]

The RF is determined by taking the difference of Actual Gas Cost Incurred and Actual Gas Cost Billed and then dividing by the estimated total residential, commercial and industrial gas sales.[1117] Dr. Anderson testified that the basis for the RF is that gas costs are collected over the year based on estimates and require a reconciliation process.[1118] Dr. Anderson testified that there are three primary differences between the proposed RF and the previous reconciliation procedure: (1) lost and unaccounted for gas (LUG) will be recovered as a part of gas cost; (2) all gas purchases and sales are included in a single calculation; and (3) to the extent there is difference from what is included in the cost of service, carrying costs on the working gas in storage owned by Distribution will be included in gas costs.[1119] Dr. Anderson testified that the inclusion of LUG in the gas cost recovery mechanism simplifies the calculation of LUG expense and makes cost recovery more precise.[1120]

TXU proposed an annual Gas Cost Reconciliation Filing Procedure (RFP).[1121] TXU proposes filing on an annual basis a certified statement with all municipalities served and the Gas Services Division a statement which reconciles its expenditures and recoveries for gas sales to residential, commercial and industrial customers, and includes a calculation of the RF.[1122] The Commission would have a sixty (60) day deadline to evaluate the RF and either issue an Administrative Order certifying the RF, or, establish a contested docket to evaluate the RF.[1123] A failure to act within sixty (60) days will result in the RF being deemed certified by the Commission.[1124] If a contested docket is established the Commission will have two hundred forty (240) days from the date of filing to issue a final order.

TXU has also proposed an Annual Gas Cost Review Filing and Protest Procedure (ACR).[1125] TXU has delineated its proposal regarding the Annual Gas Cost Review into four categories: (1) Filing Procedure; (2) Commission Review; (3) Protest Procedure; and (4) Approval Procedure.[1126] As to the proposed Filing Procedure, TXU proposes filing annually a detailed gas purchases report with all municipalities served and the Gas Services Division by September 1 for the proceeding 12-month period ending June 30.[1127] The

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[1114] TXU Exhibits 25 at 4.
[1115] TXU Exhibit 4 at 25.
[1116] TXU Exhibit 4 at 25.
[1117] TXU Exhibit 4 at 25.
[1118] TXU Exhibits 25 at 4.
[1119] TXU Exhibit 25 at 5.
[1120] TXU Exhibit 25 at 6.
[1121] TXU Exhibit 25 at 13.
[1122] TXU Exhibit 25 at 13.
[1123] TXU Exhibit 25 at 13.
[1124] TXU Exhibit 25 at 13.
[1125] TXU Exhibit 25 at 21.
[1126] TXU Exhibit 25 at 21.
[1127] TXU Exhibit 25 at 21.

report is to include gas purchases by month, by contract, and purchase prices listed for each entry.[1128]

As to its proposal for Commission Review, TXU proposes that the Commission have forty-five (45) days to conduct a prudence review of TXU's gas purchases.[1129] The Commission would have sixty (60) days to issue a detailed report and establish a contested case docket if the Commission determines such action to be necessary.[1130]

As to its proposal for Protest Procedure, TXU proposes that municipalities have forty-five (45) days to protest the report with the Commission, and that a contested case docket be established within sixty (60) days of the date that TXU filed its report.[1131] Filed protests shall "identify the specific item or items that the city or town finds objectionable."[1132]

TXU further proposes an Approval Procedure. If no contested docket is established (within the 60 day deadline for establishing a contested case docket) the Commission will issue a Final Order certifying TXU's gas purchases to have been prudently made.[1133] If no Final Order is issued by the Commission, and no contested case docket was established, the gas purchases are deemed prudent by operation of law.[1134] If a contested case docket is established, the Commission will have two hundred forty (240) days to issue a Final Order or TXU's gas purchases will be deemed prudent by operation of law.[1135]

<u>*Railroad Commission Staff's Position*</u>

Railroad Commission Staff has several proposals regarding Rider GCR-Gas Cost Recovery.[1136] Staff recommends the denial of passing rate case expenses and other surcharges through Rider GCR.[1137] Staff recommends that lost and unaccounted for gas be limited to 5 percent or actual, not to exceed 5 percent, and excluding known and measurable non-company gas.[1138] Staff also recommends a revision to allow interest to be applied to the difference between actual gas cost incurred and actual gas cost billed when calculating the reconciliation factor.[1139]

Jackie D. Standard testified as to the opinion of Railroad Commission Staff on certain aspects of the TXU's proposed Rider GCR.[1140] Ms. Standard testified that Rider GCR should not include a provision for passing through rate case expenses or other surcharges; lost and unaccounted for gas should be limited to a maximum of 5% or actual; known and measurable volumes of gas other than company gas should not be included; and that the text of Rider GCR should be revised to more clearly reflect the inclusion of

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[1128] TXU Exhibit 25 at 21.
[1129] TXU Exhibit 25 at 21.
[1130] TXU Exhibit 25 at 21.
[1131] TXU Exhibit 25 at 21.
[1132] TXU Exhibit 25 at 21.
[1133] TXU Exhibit 25 at 21.
[1134] TXU Exhibit 25 at 21.
[1135] TXU Exhibit 25 at 21.
[1136] Staff Closing Statement at 6.
[1137] Staff Closing Statement at 6.
[1138] Staff Closing Statement at 6.
[1139] Staff Closing Statement at 6.
[1140] Staff Exhibit 1at 12.

interest in the RF calculation.[1141]

Mark Brock testified on behalf of Railroad Commission Staff regarding the proposed procedures for TXU's Gas Cost Recovery, including the Annual Gas Cost Reconciliation Filing Procedure, Annual Gas Cost Review Filing and Protest Procedure, and other proposed approval procedures.[1142] In regards to the Annual Gas Cost Reconciliation, Mr. Brock testified that Railroad Commission Staff objects to the sixty (60) day and two hundred forty (240) day time periods for Commission action on the RF.[1143] Mr. Brock testified that Staff does not object to an annual review, but rather "objects to the mandate of review within a restrictive time period, the ultimatum of approval or protest and the restrictive 'closed door' indication to dialogue."[1144]

In regards to the Annual Gas Cost Review Filing and Protest Procedure, Mr. Brock testified that Staff has two main objections with regards to TXU's proposal: (1) staff objects to the time periods for Commission action because the "RRC is not bound by statute or Commission rule to indicate a requirement the RRC has a restrictive time period for the review and prudenc[e] determination of this type of filing;" and (2) "the RRC is not bound by statute or Commission rule that would indicate the RRC has only two options to either accept the filing or to establish a contested docket to determine the prudenc[e] of gas purchases."[1145]

Rose A. Ruiz testified on behalf of Staff regarding the triennial gas purchase prudence review currently in effect for TXU as it relates to the procedure proposed by TXU in this docket. Ms. Ruiz testified that TXU is proposing to change the current triennial prudence review which was established in GUD No. 8664.[1146] Ms. Ruiz testified that under the order issued in GUD 8664, TXU is required to file an application for gas cost review every three years.[1147] The Commission reviews TXU's gas procurement practices to determine if costs incurred were reasonable and necessary.[1148] The Commission also reviews TXU's affiliate transactions for reasonableness.[1149] Ms. Ruiz testified that TXU's proposed prudence review methodology "does not provide sufficient information to conduct a thorough review in order to deem gas purchases prudent and does not allow incorporated areas their statutory authority of original jurisdiction."[1150] Ms. Ruiz proposes that the Commission continue the thirty-six (36) month prudence review process.[1151] Ms. Ruiz also proposed a 36-Month Gas Purchase Prudence Review Procedure[1152] that requires TXU to provide a gas contract index listing all natural gas purchase contracts.

<u>Allied Coalition of Cities' Position</u>

ACC has proposed gas cost correction factors (GCCF) to adjust volumes to prevent the over-recovery of gas cost. ACC's GCCF is based on adjusting TXU's metered gas volumes for changes in elevation

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1141 Staff Exhibit 1at 12.
1142 Staff Exhibit 1at 3.
1143 Staff Exhibit 3 at 6.
1144 Staff Exhibit 3 at 6.
1145 Staff Exhibit 3 at 8.
1146 Staff Exhibit 2 at 3.
1147 Staff Exhibit 2 at 4.
1148 Staff Exhibit 2 at 4.
1149 Staff Exhibit 2 at 4.
1150 Staff Exhibit 2 at 8.
1151 Staff Exhibit 2 at 8.
1152 Staff Exhibit 2 at 11.

andatmospheric pressure. Bill R. McMorries, P.E. testified on behalf of ACC regarding the proposed GCCF.[1153]

Mr. McMorries proposed a method to correct the volumes of gas for residential, commercial and industrial customers receiving service from meters not corrected for pressure.[1154] Mr. McMorries proposed method divides TXU's service area into eight elevation or pressure zones with gas cost correction factors so that customers' measured gas volumes are more accurate.[1155] ACC recommends the GCCF "because the Company's gas is priced based upon 14.65 psi pressure, yet it is delivered to meters with greater or less psi because of atmospheric and elevation conditions."[1156] ACC argues that the GCCF is needed to prevent TXU from discriminating against customers located in higher elevations by recovering more than its actual gas cost from these customers.

ACC further argues that TXU's proposed procedural deadlines inappropriately shift the burden of proof to entities challenging TXU's gas costs, instead of requiring TXU to establish the reasonableness of the costs.

City of Dallas's Position

Dallas argues that TXU's proposed Rider GCR is not reasonable for two reasons; One, the proposed GCR "includes a return component on investment;" and two, the proposed procedures improperly seek to remove original municipal jurisdiction over these rates.[1157] Dallas argues that TXU's proposal whereby Rider GCR recovers gas costs associated with increases in working gas in storage constitutes a request to recover "invested capital/rate base."[1158] Dallas argues that GCR is defective for recovering returns on "invested capital/rate base" and should be rejected.

Dallas also argues that the "second problem with the proposed GCR Rider is the proposed elimination of original municipal jurisdiction."[1159] Citing TEX. UTIL. CODE ANN. §104.003(c) (Vernon1998), Dallas argues that GURA does not contemplate Commission review of gas costs in city-gate proceedings.

Examiners' Recommendation

With regard to TXU's proposals for recovery of gas costs, the Commission has two broad issues that must be decided. The first issue concerns the reasonableness of the gas cost recovery mechanism itself. The second issue concerns the reasonableness of TXU's proposed deadlines and Commission procedures with respect to implementing Rider GCR.

TXU has proposed a Gas Cost Recovery Factor (GCRF) to be comprised of four components: (1) Estimated Cost of Gas Factor (ECGF); (2) Reconciliation Factor (RF); (3) Taxes; and (4) Adjustments. The only argument made against this general structure of the GCRF was made by ACC. ACC essentially argues that the GCRF is not reasonable because it does not include an additional factor to adjust for

[1153] ACC Exhibit 224.
[1154] ACC Exhibit 224 at 16-17.
[1155]ACC Exhibit 224 at 16-17.
[1156] ACC Initial Brief at 134.
[1157] Dallas Closing Argument at 55.
[1158] Dallas Closing Argument at 55.
[1159] Dallas Closing Argument at 56.

inaccuracies in metered volumes due to changes in elevation. ACC argues, through the testimony of Mr. McMorries, that inaccurate meter measurement of gas volumes will allow the utility to over-recover gas cost. ACC's argument is based on the indisputable principle that customers should only pay for gas volumes they actually receive, therefore accurate measurement of those volumes is important to prevent over or under recovery of gas cost. However, the evidence presented does not lead the Examiners to conclude that differences in elevation throughout TXU's service area lead to inaccurate meter readings of gas volume. Further, the evidence does not indicate that the Gas Cost Correction Factor (and corresponding eight elevation districts) proposed by ACC will actually provide gas volumes delivered to customers with more accuracy. Therefore, the Examiners do not recommend the adoption by the Commission of the GCCF proposed by ACC.

In general, the Examiners find that a GCRF comprised of four components (ECGF, RF, Taxes and Adjustments) to be a reasonable mechanism for the utility to recover its gas costs and recommend Commission adoption of the GCRF as such. However, each of the components of the GCRF contain elements that parties have contested. For reasons specified below, the Examiners do not recommend adoption of the components as originally proposed by TXU.

The parties do not appear to have objected to TXU's proposed Estimated Cost of Gas Factor. Although several parties object to TXU's lost and unaccounted for gas factor in and of itself, there does not appear to be an objection that TXU recover the cost of lost and unaccounted for gas through the GCRF. This is the first time TXU has proposed recovering the cost of gas of LUG through its gas cost recovery mechanism.[1160] Dr. Anderson testified that it is necessary for TXU "to buy gas and thus incur gas costs to supply LUG. The inclusion of LUG in the gas cost recovery mechanism greatly simplifies the calculation of LUG expense and makes cost recovery more precise."[1161] The cost of gas that is lost and unaccounted for is obviously a cost of gas incurred by the utility. It is reasonable to recover the allowable portion of these costs through the gas cost recovery mechanism as opposed to embedding them in rates for gas service. The Examiners find that it is reasonable to recover the costs of gas associated with LUG through the GCRF. Therefore the Examiners recommend approval of the ECGF component of the GCRF.

The parties voiced objections to TXU's proposed Recovery Factor. Dallas's objection to the RF is that it will allow the recovery of the return on investment the utility is allowed to earn on working gas in storage. The underlying issue of Dallas's objection is whether or not TXU's gas cost recovery mechanism should be used solely for the recovery of the commodity costs of gas. Testimony justifying the recovery of return on investment in working gas in storage is scant to none although the item appears in Dr. Anderson's schedules.[1162] Further, return on investment with regard to TXU's gas inventories is not a concept the average customer of TXU is likely to associate with the commodity cost of gas. Recovery of this item through the gas cost recovery mechanism is therefore misleading. The Examiners recommend denial of TXU's proposal to recover the return on investment associated with working gas in storage through Rider GCR.

[1160] TXU Exhibit 25 at 5.
[1161] TXU Exhibit 25 at 6.
[1162] TXU Exhibit 25 at 14, 17, 19 and 20.

Staff objects to the proposal of TXU to recover rate case expenses through the RF. TXU offered rebuttal testimony that the utility only intended to recover rate case expenses associated with contested case dockets associated with gas cost recovery issues and not the present case. The Examiners agree with Staff's objection that rate case expenses should not be recoverable through the GCRF. The Examiners recommend the denial of the proposed inclusion of rate case expenses, whether in this docket or in subsequent dockets, because such an expense is not necessarily associated with the commodity cost of gas. If the underlying policy of the gas cost recovery mechanism is for the utility to transparently recover the commodity cost of gas sold to its customers, rate case expenses and other items not directly associated with commodity gas cost should not be recovered thereby.

Staff also proposes that the wording in Rider GCR should be revised so that it is clear that interest will be applied to the difference between Actual Gas Cost Incurred and Actual Gas Cost Billed when calculating the Reconciliation Factor. The Examiners recommend the Commission disallow the recovery of any interest through Rider GCR. First, there was no testimony submitted by the utility justifying the recovery of interest on this item, other than the inclusion of this item in Dr. Anderson's Schedules.[1163] Second, there is no indication guaranteeing that cash would actually be borrowed by TXU from a third party lender to fund such purchases and result in interest expense. Third, there is no indication that if such an interest expense were actually incurred by the utility, that the interest expense was not factored into the utility's cash working capital model and thus recovered through rates for cost of service. Fourth, if the interest were generated on internally borrowed cash, the application of the Prime Rate by Dr. Anderson is unreasonable and excessive.

TXU bases its procedural proposals for the annual reconciliation filing and the annual prudence review on the utility's need for efficient regulatory decision making where TXU's actions are dependant on regulatory approval. Dallas alleges TXU's procedural proposals would violate GURA because the Commission would be illegally affecting the jurisdiction, power or duty of a municipality that has elected to regulate and supervise a gas utility in the municipality.[1164] The Examiners find Dallas's objection to have little weight because TXU does not propose that the Commission, directly or indirectly, hinder a municipality from regulating a gas utility within that municipality's jurisdiction. Rather, the recommended procedural mechanisms would be ordered as a result of a contested case docket over which the Commission has jurisdiction. Whether or not the Commission orders TXU to file gas prudence reviews at the Commission does not directly or indirectly hinder the regulatory actions taken by a municipality which has jurisdiction over TXU within that municipality.

ACC has argued that TXU's proposals inappropriately shift the burden of proof to entities challenging TXU's gas costs. ACC does not specifically argue how the proposal improperly shifts TXU's burden of proof. The Examiners do not find that TXU has proposed the elimination of its requirement to establish the prudence of its gas cost purchases.

Railroad Commission Staff offer several objections to the deadlines for TXU's proposed procedures. The Examiners agree with Staff that TXU's proposed procedures are unreasonable. The Examiners agree with TXU that regulatory decision making should be done in an expeditious and efficient manner. However,

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[1163] TXU Exhibit 25 at 14 and 20.

[1164] City of Dallas Closing Brief at 57, citing TEX. UTIL. CODE ANN. §102.002 (Vernon 1998).

TXU's proposal would have the effect of establishing unique procedural rules not applicable to other gas utilities and which limit the ability of TXU's customers to participate in contested case dockets before the Commission. Such a proposal is more suitable for a proposed rule-making. The Examiners recommend that the Commission deny TXU's proposed Reconciliation Filing Procedure and other procedural deadline proposals.

Staff objects to the annual filing proposed by TXU in its proposed Annual Gas Cost Review Filing and Protest Procedure (ACR). Staff objects to a yearly filing for the ACR on the basis that it will prevent an effective review of the prudence of TXU's gas purchases. Staff recommends the adoption of a 36-Month Gas Purchase Prudence Review Procedure which is the same time period as that adopted in GUD No. 8664. The Examiners agree with Staff that a 36-month gas purchase prudence review is reasonable and should be adopted by the Commission.

The Examiners find that the evidence establishes that TXU's proposed quarterly filing of the GCRF is reasonable and should be adopted by the Commission.

X. Cost Allocation

Cost allocation is the process of allocating costs to different customer classes. The allocation of cost responsibility for each customer class is integral to determining the rates each customer class is charged for gas service. In this docket TXU proposed rates for six (6) different customer classes. On the pipeline portion TXU proposes two customer classes: (1) city gate service and (2) pipeline transportation. On the distribution portion, TXU has proposed four customer classes: (1) residential sales; (2) commercial sales; (3) industrial sales; and (4) transportation.[1165] TXU's cost allocation study attempts to allocate cost responsibility to these six classes of customers and involves four major steps: functionalization, classification, the development of allocation factors; and allocation

A. Functionalization

Functionalization is the process whereby costs are identified by their function in order to determine which customer classes should bear those costs. The basic issue the Commission must decide is whether the utility's proposal regarding cost functionalization is reasonable.

TXU's Position

TXU proposes identifying all costs according to four major functions: transmission, storage, distribution, and general.[1166] Additionally, for the Pipeline portion of its system TXU proposes the functionalization of mains on the pipeline system as providing one of two major functions: (1) bulk transmission or (2) network transmission. TXU defines bulk transmission and network transmission as follows:

> Bulk Transmission consists of the large diameter, high pressure pipeline from the Waha Hub to the Katy Hub, including the large diameter lateral pipeline connecting to the Bethel storage. Network Transmission consists of the mains that connect the Bulk Transmission

[1165] TXU Exhibit 23 at 4.
[1166] TXU Exhibit 23 at 5.

> pipeline, pipelines from other sources of gas supply, and other transmission pipelines, and smaller, lower pressure mains that integrate Bulk Transmission and storage into a flexible, widely distributed delivery network for service City Gates and large volume customers.[1167]

TXU proposed allocating the costs associated with these two categories to City Gate and Pipeline Transportation customer classes by using the 4MDU demand allocator.[1168] (*See below*)

Allied Coalition of Cities' Position

ACC's position is that TXU's proposed functionalization of the pipeline system into bulk transmission and network transmission is a major flaw and should be rejected. ACC's position is that this functionalization is inconsistent with Commission precedent, is arbitrary and incomplete, and unreasonably results in a 5% increase in the allocation of transmission plant to Distribution customers.[1169] ACC argues that TXU's functionalization of its pipeline system into bulk transmission and network transmission contradicts the utility's theory of an integrated system.[1170] ACC argues that the bulk/network functionalization artificially decreases costs assigned to bulk service and "arbitrarily reduces the share of return, income taxes, property taxes and depreciation expense that bulk transmission must contribute."[1171] ACC argues that the bulk/network functionalization is "incomplete because it overstates the peak day demand that 'network' customers impose upon 'bulk' transmission."[1172] ACC argues that TXU's proposed bulk/network functionalization is similar to that which was proposed and rejected in GUD No. 8976.[1173]

Industrial Gas Users' Position

IGU agrees with TXU's proposed functionalization of its system. "TXU has properly functionalized and classified its costs."[1174]

Examiners' Recommendation

TXU's proposed functionalization of its system as transmission, storage, distribution, and general was unopposed by the parties. Identifying costs associated with transmission, storage, distribution and general functions of the TXU system is reasonable for purposes of conducting a cost allocation study. The Examiners recommend the Commission approve TXU's proposed four tier functionalization.

The Examiners recommend that the proposed additional functionalization of TXU's pipeline system into bulk transmission and network transmission be rejected by the Commission. TXU provides no testimony, justification, or explanation as to why the pipeline system should be additionally functionalized. There has been no demonstration by the utility that such an additional functionalization is necessary and reasonable. TXU has not demonstrated the effects such a functionalization results in when allocating costs among customer classes. TXU has clearly not met its burden of proving to the Commission that such a methodology is reasonable and in accordance with sound rate-making principles. TXU's proposed

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1167 TXU Exhibit 23 at 7.
1168 TXU Exhibit 23 at 7.
1169 ACC Initial Brief at 139.
1170 ACC Initial Brief at 140.
1171 ACC Initial Brief at 140.
1172 ACC Initial Brief at 142-143.
1173 ACC Initial Brief at 142-143.
1174 Initial Brief of Industrial Gas Users at 7.

bulk/network functionalization distorts cost allocation by increasing the allocation of costs to distribution customers. TXU proposed a similar functionalization of the TXU Lone Star Pipeline system in GUD No. 8976. The Examiner recommended rejection and the Commission rejected the functionalization proposed by TXU in GUD No. 8976.[1175]

B. Classification

Classification involves classifying items – capital investment, revenues, and expenses – by elements of cost causation. Classification involves associating costs incurred by the utility with the factors that most directly cause those costs to be incurred.

TXU's Position

TXU proposed the following cost causation elements: customers, demand, volume, or combinations thereof. TXU proposed classifying all fixed costs as demand or customer related, and variable costs as volume related.[1176] TXU additionally proposed a Minimum Distribution System methodology whereby distribution mains are classified as either customer-related or demand related using the minimum distribution system.[1177] The proposed Minimum Distribution System method is only applied to TXU's distribution system. The broad issue the Commission must decide is whether TXU's proposed classification of costs is reasonable. More specifically, the Commission must decide if TXU's use of a proposed Minimum Distribution System Methodology is reasonable.

TXU uses a proposed Minimum Distribution System analysis to classify a portion of its Distribution Mains (Account 376) as customer-related and the remaining portion as demand-related. The minimum distribution system is the minimum-sized distribution system that would be installed to serve new customers and therefore TXU classifies this as customer-related cost. TXU proposes calculating the minimum distribution system by adjusting the cost of new 2" plastic distribution pipe ($5.57 per foot) to original cost by multiplying by a ratio of gross mains investment at original cost to mains investment at replacement cost, yielding an adjusted cost per foot of $2.99. The adjusted cost per foot is multiplied by the total footage of mains, adjusted for depreciation, and yields a minimum distribution system cost of approximately $287 million.[1178] Thus, TXU is proposing to classify approximately $287 million of its Distribution System Mains (Account 376) as customer-related and the balance of Distribution System Mains, approximately $377 million, as demand-related.[1179]

Allied Coalition of Cities' Position

ACC recommends that TXU's minimum distribution system method be rejected and TXU's classification and allocation of costs associated with distribution mains be rejected.[1180] ACC argues that TXU's

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[1175] GUD No. 8976 Proposal For Decision at 98-103. Interestingly, it appears that in GUD No. 8976 TXU submitted significantly more testimony, argument, explanation and proof regarding this sort of functionalization than was submitted in this docket. If TXU was unable to prove the reasonableness of such a functionalization in GUD No. 8976, why would the utility be able to establish its burden of proof in this case with less evidence?

[1176] TXU Exhibit 23 at 5

[1177] TXU Exhibit 24 at 37-42 (Exhibit GLG–4).

[1178] TXU Exhibit 23 at 9.

[1179] TXU Initial Post-Hearing Brief at 125.

[1180] ACC Initial Brief at 150.

calculation of minimum system costs using system replacement cost and minimum system replacement cost is inconsistent.[1181] ACC argues that TXU's calculation of minimum distribution system replacement cost using an engineering estimate procedure and the calculation of the system replacement cost based on the Handy-Whitman Index is inconsistent and inaccurate.[1182]

ACC also argues that TXU's actual investment in distribution mains does not correlate with TXU's calculation of minimum system costs. "TXU's minimum system analysis fails to account for the fact that the number of feet of main installed to serve a customer varies based upon several components, including customer size, density of development, and customer location. TXU's failure to address these variances results in an allocation that is systematically biased against the residential class."[1183]

<u>Association of TXU Municipalities' Position</u>

ATM's position is that the proposed minimum distribution system methodology for classifying distributions should be rejected by the Commission.[1184] Jeffrey Rudolph testified on behalf of ATM that TXU's minimum-system method "is based on development of a vaguely defined hypothetical system comprised of two-inch poly pipe."[1185] Mr. Rudolph also testified that the Commission should "either 1) cap the customer-related classification of Account 376 at 33%, or 2) adopt Bonbright's conclusion that minimum-system costs do not belong to any cost function."[1186] ATM argues that a customer classification of 43.23% of Account 376 results in disproportionate cost burdens for residential and commercial rate-payers because residential and commercial customers are 99.9% of TXU's total number of customers.[1187] ATM further argues that the minimum-system method unreasonably affects other cost classifications and allocations due to TXU's use of numerous composite allocators (*See Below*).[1188] ATM argues that the minimum-system method is subjective and "reflects neither minimum size, capacity, nor usage, and thus its theoretical foundation is flawed."[1189] ATM also argues that in GUD No. 9145, "the Commission approved a customer classification of 16.55%, about one-third as large as the 43.25% customer classification proposed by TXU in this case."[1190] ATM argues that TXU has not provided sufficient evidence or established its burden of proof to justify such an increase in the allocation of costs to residential and commercial customers for Account 376 is reasonable. ATM recommends that the Commission either allocate 1/3 of Account 376 on a customer basis, or evenly apportion the 43 percent attributed to customers by TXU on a demand, energy and customer basis.[1191]

<u>City of Dallas's Position</u>

Dallas argues that the assignment of 43.25 percent of the costs of mains as customer-related using the minimum-system method is problematic. Dallas points out that the cost allocation study used by TXU in GUD No. 9145 used the zero intercept method, and resulted in an allocation of 16.5 percent to customers.

[1181] ACC Initial Brief at 151-152.
[1182] ACC Initial Brief at 151-152.
[1183] ACC Initial Brief at 151-152.
[1184] ATM Initial Brief at 67.
[1185] ATM Exhibit 121 at 12.
[1186] ATM Exhibit 121 at 14.
[1187] ATM Initial Brief at 68.
[1188] ATM Initial Brief at 68.
[1189] ATM Initial Brief at 69.
[1190] ATM Initial Brief at 70.
[1191] ATM Initial Brief at 71.

Dallas recommends that the Commission "utilize the update to the prior study which resulted in a zero intercept value of $4.09 per foot. The result of the study is allocation of $302,734,524 of mains on a customer basis instead of TXU's $412,033,944."[1192]

Industrial Gas Users' Position

IGU argues that it is appropriate to classify distribution mains as having both demand and customer cost components and that TXU correctly does so using the minimum distribution system method.[1193] IGU also argues that "the criticisms of TXU's minimum system methodology advanced by ACC and ATM are invalid and appear calculated only to shift costs from residential customers to other classes."[1194]

Examiners' Recommendation

The parties did not contest TXU's general proposal to classify costs as being driven by demand, volume, customers, or a combination thereof. The Examiners find that TXU's proposal to classify costs as either customer-related, demand-related, volume-related, or a combination thereof is reasonable and recommend the Commission adopt TXU's proposal to do so.

The parties did contest TXU's proposed Minimum Distribution System methodology used in the classification of Account 376, Distribution Mains. The initial issue regarding TXU's proposal regarding Account 376 is whether it is reasonable to classify a portion of that account as demand-related and another portion as customer-related. TXU's basis for such a division is that costs arise on a certain minimum portion of the distribution system primarily because "the system would have to be in place to provide the potential for service even though the customer did not use any gas or place any demand on the system."[1195] In effect, TXU incurs distribution mains costs for customers whether or not they use gas. TXU argues that these costs are driven by the number of customers, not the demand for gas or the volumes of gas sold. The Examiners find this to be reasonable and recommend the Commission adopt TXU's proposal to classify a minimum portion of its Account 376 as customer-related and the remainder as demand-related.

The other issue involving TXU's proposed Minimum Distribution System methodology is the reasonableness of the method for calculating the minimum portion of the system (which will be classified as customer-related for cost allocation purposes). The parties' objections to TXU's proposed method are essentially that the calculation is flawed. TXU's proposed method involved estimating the actual cost of installing new two inch distribution pipe and obtaining estimated value for the embedded minimum distribution system. TXU also applied the Handy-Whitman index to the historical cost of its mains to estimate the replacement cost of the system. TXU calculated the customer portion of the distribution system by comparing these two amounts (estimated current replacement cost of system with estimated actual cost of installing 2 inch mains) to obtain the percentage of customer related distribution mains, approximately 43%. The Examiners find this method to be a reasonable method of estimating the minimum system portion of TXU's distribution mains account. The Examiners recommend the Commission adopt TXU's proposed Minimum Distribution System method for this case and that Account 376 be classified as 43.2% customer-related and 56.8% demand-related.

[1192] City of Dallas Closing Argument at 60.
[1193] IGU Initial Brief at 19.
[1194] IGU Initial Brief at 19.
[1195] TXU Exhibit 23 at 8.

C. Allocation Methodology

Cost allocation is the process of assigning responsibility for costs to the various customer classes. In this docket, TXU proposed a classification of costs as being driven by customers, demand, volume, or combinations thereof. Determining the appropriate allocation methodology involves a determination of the reasonableness of how these costs are assigned. The Commission must determine if TXU's proposal for allocating costs associated with demand is reasonable. Likewise, the Commission must determine if TXU's proposal for allocating costs associated with volume and customers is reasonable. The allocation methodology issue primarily contested by the parties is the proposed method by which TXU allocates demand driven costs.

__TXU's Position__

First of all, TXU proposes allocating fixed costs as demand driven costs. TXU proposes the allocation of fixed costs by using the average of the peak daily usage occurring during each of the peak volume months of December through March. This is referred to as the Four Maximum Daily Usage method ("4MDU").[1196] Mr. Houle testifies that the "most important criterion in the selection of a demand allocation methodology is the annual load shape of TXU Gas."[1197] He further testifies that TXU's load shape is characterized by a winter peaking pattern and that the system load in the winter months of December through March exceeds the other months by a substantial margin. Mr. Houle testifies that the winter months are the most important demand period because the amount of capacity required by a utility is determined by the maximum load that must be served during the peak period.

TXU proposes developing customer allocation factors by using the number of customers in each rate class at the end of the test year. TXU proposes developing volume allocation factors based on the actual gas usage of each customer class.[1198] Mr. Goble proffered testimony regarding the Applicant's capacity demand data and the development of allocation factors.[1199] Mr. Goble testified that the proposed 4MDU method "correctly and accurately reflects the manner in which capacity costs are incurred by the Company."[1200] Mr. Goble testified that the TXU system is a winter-peaking system and that the use of four winter months to calculate capacity is appropriate.[1201] Mr. Goble testified that MDU data for pipeline customers was based upon actual recorded data. The MDU data for City Gate Customers is adjusted for weather normalization, end-user customer growth, and billing cycle differences. MDU for industrial sales and transportation customers is statistically derived.[1202]

__Allied Coalition of Cities' Position__

ACC's position is that the proposed 4MDU allocation methodology should be rejected. ACC argues that use of the "4MDU method ignores the costs imposed upon the system by off-peak usage and unreasonably

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1196 TXU Exhibit 23 at 6.
1197 TXU Exhibit 23 at 6.
1198 TXU Exhibit 23 at 5.
1199 TXU Exhibit 24 at 10–13.
1200 TXU Exhibit 24 at 10–13.
1201 TXU Exhibit 24 at 10–13.
1202 TXU Exhibit 24 at 10–13.

understates the cost of using the system during the months of April through November."[1203] ACC argues that TXU's proposed 4MDU method creates a free-rider problem and provides free off-peak service because it does not account for off-peak usage.[1204] ACC argues that TXU's proposed allocation of pipeline operation and maintenance expenses should be rejected.[1205] ACC recommends the allocation of main and station operation expenses based on annual usage with an adjustment to reflect higher Mcf costs during December through March.[1206] ACC also recommends the allocation of 32 percent of distribution's portion of pipeline costs based on annual usage with an adjustment that provides a pass through of the seasonal differences in cost.[1207]

Association of TXU Municipalities' Position

ATM's position is that the Commission should reject the use of a 4MDU allocator to allocate costs. ATM argues that using 4MDU results in unreasonable allocations of costs.[1208] ATM recommends modification of TXU's proposed 4MDU method by equally weighting annual Mcf throughput and demand in the allocation of the demand-related portion of Account 376 and pipeline costs.[1209] ATM argues that demand allocation factors that are based on a small number of days yield more volatile results and are inconsistent from year to year. ATM argues that the proposed 4MDU method relies on estimated usage for transportation and sales customers and may be invalid. ATM also argues that use of 4MDU to allocate costs represents a departure from Commission policy and TXU policy.[1210] ATM also recommends the 50/50 weighting of demand and annual throughput for the allocation of distribution system costs for plant-in-service, related depreciation, and return.[1211] ATM recommends the 50/50 weighting for the allocation of operations and maintenance expenses on the TXU pipeline system.[1212]

City of Dallas's Position

Dallas's position is that the Commission should reject the use of a 4MDU allocator to allocate costs. Dallas proposes use of the Seaboard (50/50) method to allocate demand related investment.[1213] Daniel Lawton testified on behalf of Dallas that demand measured using 4MDU has "significant deficiencies."[1214] Dallas's expert recommended "that the demand allocator be based on the Seaboard Method employing or weighting the '4MDU' and annual throughput on a 50/50 basis."[1215]

Chaparral Steel's Position

Chaparral Steel argues that the 4MDU method most closely correlates to actual class cost causation on the TXU system.[1216] Additionally, Chaparral argues that TXU should discount the 4MDU allocation of cost

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[1203] ACC Initial Brief at 144.
[1204] ACC Initial Brief at 145.
[1205] ACC Initial Brief at 145-146.
[1206] ACC Exhibit 61 at 7.
[1207] ACC Exhibit 61 at 7.
[1208] ATM Initial Brief at 63.
[1209] ATM Initial Brief at 63.
[1210] ATM Initial Brief at 64.
[1211] ATM Initial Brief at 66.
[1212] ATM Initial Brief at 66.
[1213] Dallas Exhibit 82 at 30.
[1214] Dallas Exhibit 82 at 29.
[1215] Dallas Exhibit 82 at 31.
[1216] Chaparral Initial Post Hearing Brief at 13.

to interruptible classes by 50%.[1217] Chaparral argues that interruptible customers are receiving inferior gas service and should not bear the same cost responsibility for the incurrence of peak-driven costs.[1218]

Industrial Gas Users' Position
IGU recommends the rejection of TXU's proposed 4MDU allocator in favor of a single coincident peak allocator. IGU argues that because system capacity is determined by peak usage the coincident peak allocator is the most appropriate method as it represents peak demand. IGU further argues that TXU has not demonstrated any atypical conditions that would mandate the usage of the 4MDU allocator over the coincident peak method. IGU further argues that ACC, ATM, and Dallas advocate the Seaboard method as means to shift costs to high load customers.

Examiners' Recommendation
The allocation issues most contested concern TXU's proposal to allocate all fixed cost as demand driven costs and allocate them using the 4MDU method. The evidence submitted by TXU indicates that the TXU system is a winter-peaking system. The peak usage of TXU's system occurs during the months of December through March. As a result of this winter-peaking pattern, TXU based its demand allocation method on maximum daily use patterns during these four months, hence the 4 maximum daily usage method ("4MDU"). One party argues that the single peak usage day of the test year is a better indicator of system demand. However, the Examiners find that use of a single peak day is not a reasonable method for estimating system demand. There is no evidence that a single coincident peak indicator will more accurately measure system demand, will not overstate abnormal usage patterns, or is more reflective of true peak demand by customer class. Further, there is no evidence that a single coincident peak indicator accurately measures peak demand behavior per customer class and is statistically significant for cost allocation purposes. The weight of the evidence indicates that it is reasonable to estimate peak system demand per customer class on TXU's distribution and pipeline systems by determining the peak usage days during the months of December through March.

The Examiners find that TXU's proposed 4MDU concept for its distribution system is reasonable. However, the Examiners find that TXU's calculation of maximum daily usages for its pipeline system is unreasonable. TXU calculated MDU's on its pipeline system using cumulative volume amounts that are based on its distinction between bulk and network transmission. TXU did not submit sufficient evidence justifying its cumulative adjustments to pipeline volumes when calculating MDU's and has not met its burden of proof establishing the reasonableness of the adjustments. The Examiners find that TXU's method of calculating MDU's for its pipeline system is unreasonable and yields distorted results because it allocates more costs to city-gate customers than to pipeline transportation customers than an allocation based on annual volumes delivered. Tables 10.1 and 10.2 illustrate 4MDU calculations, volumes and corresponding percentages using TXU's adjustments and the Examiners' recommended use of delivered volumes. The Examiners recommend calculating MDU's for the pipeline portion of the system using delivered volumes.

[1217] Chaparral Initial Post Hearing Brief at 13.
[1218] Chaparral Initial Post Hearing Brief at 13.

Table 10.1 Pipeline 4MDU

4MDU with adjusted volumes used	Total	City Gate Service	Pipeline / Transportation
TXU Proposed (Cumulative)	6,034,070	4,857,557 (80.5%)	1,176,513 (19.5%)
Examiners' Recommended (Delivered)	2,386,243	1,802,317 (75.5%)	583,926 (24.5%)

Table 10.2 Pipeline Volumes

Volumes Delivered	Total	City Gate Service	Pipeline / Transportation
TXU Proposed (Cumulative)	899,223,470	561,500,439 (62.4%)	337,723,031 (37.6%)
Examiners' Recommended (Delivered)	368,409,593	209,109,982 (56.8%)	159,299,611 (43.2%)

The Examiners also conclude that the use of the 4MDU method to allocate fixed costs on TXU's pipeline and distribution systems does not accurately allocate the costs based on the overall use of the systems by all customer classes. Essentially the arguments against TXU's proposal are that use of a 4MDU allocator will yield unreasonable allocation results; it represents a significant departure from prior Commission policy, and; the costs associated with average throughput and the role of off-peak customers in cost causation are minimized.

The Examiners recommend that the Commission reject TXU's use of the 4MDU allocator as proposed. The Examiners recommend that accounts allocated by TXU using the 4MDU allocator be allocated as 50% Capacity and 50% Commodity. That is, the Examiners recommend the allocator be equally weighted as 50% 4MDU and 50% volume. As is shown on the following chart, the Examiners' recommendation for Pipeline is still a departure from GUD No. 8976, though not as significant a departure as the allocation method proposed by TXU. The evidence indicates that the allocators based on number of customers and volumes delivered are calculated correctly, do not distort results and are reasonable. The Examiners recommend that the Commission adopt TXU's customer and volume allocators as proposed by TXU.

Table 10.3 Pipeline Allocation

Pipeline Capacity Allocation	City Gate Service	Pipeline / Transportation
TXU Proposed (4MDU Cumulative Volumes)	80.5%	19.5%
50/50 Capacity / Commodity - Cumulative Volumes	71.5%	28.5%
Examiners' Recommended - Actual Volumes (50/50 Capacity / Commodity)	66.15%	33.85%
Current Allocation - GUD No. 8976 (fixed costs)	46.18%	53.82%

Table 10.4 Distribution Allocation

Pipeline Capacity Allocation	Residential	Commercial	Industrial Sales / Transportation
TXU Proposed (4MDU)	57.38%	29.25%	13.37%
Examiners' Recommended - (50/50 Capacity / Commodity	49.97%	27.98%	22.04%

Cost Allocation Calculations and Spreadsheets

TXU's application included schedules and work papers, which record in part the calculations made according to its cost allocation methodology. The Examiners note for the record that TXU's cost allocation methodology and the calculations based on it were overly complex, difficult to understand, and burdensome on the intervening parties and the Examiners. The electronic spreadsheets eventually provided by TXU were of limited value with respect to cost allocation, based in part on proprietary software of one of TXU's consultants, and according to ACC witness Nalepa, "...examined and found to contain enough errors, hard coded numbers, and lost links that ACC decided not to rely on the model for comparing changes to TXU's filed case."[1219] The Examiners experienced similar difficulty with TXU's financial model and question whether any purported increased accuracy of cost allocation afforded by the complexity of the model outweighs the resulting lack of transparency and costs to the parties, the Examiners, and the Commission resulting from that complexity. The Examiners recommend that future filings with the Commission rely on financial methodology and calculations that are complete, straightforward, transparent, not based in part or in whole on proprietary software, and are initially filed both in hard copy and as electronic spreadsheets using Microsoft Excel format.

[1219] ACC Exhibit 4 at 5-6.

XI. Rate Design

The process of rate design concerns the design, structure and implementation of rates to generate the revenues approved by the Commission for the utility. There are several rate design issues the Commission must decide in this docket. Notably, this is the first time the Commission will be considering the implementation of uniform system-wide rates for all customers of TXU. This is the first time the Commission has been requested by TXU to set "bundled" rates – rates that bundle transmission and distribution rates exclusive of a city-gate rate. Further, the Commission is being asked to set rates for industrial sales and transportation customers.

A. Initial Policy Issues: System-Wide Rates, Bundled Rates

TXU's Position
TXU proposes system-wide rates for six classes of service: City Gate Service, Pipeline Transportation, Residential Sales, Commercial Sales, Industrial Sales, and Transportation.[1220] TXU has proposed rates that are standard for each customer class across its system.[1221] Mr. Houle testified that system-wide rates "will provide greater price transparency for customers and ensures the opportunity for cost recovery by the Company."[1222] TXU argues that its customers will benefit from system-wide rates because one system-wide rate case in place of numerous municipal rate cases should result in lower rate case expenses.[1223] TXU also argues that similarly situated customers will pay uniform rates under a system-wide rate structure. TXU further argues that the effects of additional investment will be equalized across its system, individual municipalities will not be economically disadvantaged, and savings from more efficient administration of rates and contracts will be the result of the Commission approving system-wide rates.[1224] TXU argues "that setting rates on a system-wide basis will result in rates that are more transparent, less complicated, and more consistent with current state and national ratemaking policy."[1225]

Another unique proposal advanced by TXU in this docket is the company's proposal to "bundle" distribution and pipeline rates. TXU proposes a single rate for each customer class that includes both pipeline and distribution components "bundled" into one rate.[1226] TXU argues that its proposed rates provide one clear, easily understandable rate for receiving gas service.[1227] TXU argues that bundling transmission and distribution rates provides complete price transparency and that customers can clearly see and understand the rates and charges TXU charges for service on its system.[1228]

TXU has presented testimony that the objective of its rate design is to move all customer rate classes to a 100% relative rate of return. TXU has proposed limiting customer class relative rates of return by not

[1220] TXU Exhibit 23 at 10.
[1221] TXU Exhibit 23 at 10.
[1222] TXU Exhibit 23 at 11.
[1223] TXU Initial Brief at 147.
[1224] TXU Initial Brief at 147.
[1225] TXU Initial Brief at 149.
[1226] This has been referred to as a single rate for gas service from "wellhead to burner tip."
[1227] TXU Initial Brief at 149.
[1228] TXU Initial Brief at 149.

imposing rate increases or decreases greater than 10% on any customer class.[1229] TXU argues that it is reasonable to limit the impact of rate increases on customer classes.[1230] Mr. Houle offered the following table to summarize the proposed relative rates of return.[1231]

TXU's Proposed Relative Rates of Return

Rate Class	**% Increase** (with gas cost)	**% Increase** (without gas cost)	**TXU Proposed Relative Rate of Return**
Rate CGS	10%		86%
Rate PT	0%		160%
Rate R	10%	20%	78%
Rate C	2%	4%	140%
Rate I and Rate T	0%	0%	328%

Association of TXU Municipalities' Position

ATM does not oppose the Commission setting system-wide rates for rate components for which geographical differences cannot be demonstrated.[1232] ATM argues that certain rate components, such as pipe relocation costs, should be assessed on ratepayers within the cities requiring such relocations. ATM recommends the Commission reduce TXU's revenue requirement by removing all relocation costs where there is no relationship to cost requirements.[1233]

ATM opposes TXU's proposal to establish bundled rates.[1234] ATM argues that unbundled rates – rates that distinguish between pipeline and distribution service – should be approved by the Commission because unbundled rates facilitate review of the distribution-only portion of the rates by municipalities.[1235] ATM also argues that unbundled rates provide better price signals and transparency to energy consumers. ATM also argues that unbundled rates provide more information to consumers who have alternative gas supply choices.[1236]

Brazos Electric Power Cooperative's Position

Brazos objects to the ultimate rates and relative rates of return that transportation customers will bear under TXU's proposed rate design.[1237] Brazos argues that TXU's proposed 10% limit on rate increases is unreasonable and should be increased to approximately 11.2% so that customer classes pay no more than their actual cost of service. Brazos proposes that transportation customers bear no more than a 100%

[1229] TXU Exhibit 23 at 10.
[1230] TXU Initial Brief at 150.
[1231] TXU Exhibit 23 at 10. In general, Rate CGS is for city-gate service to LDCs; Rate PT is for transportation customers; Rate R is for residential customers; Rate C is for commercial customers; Rate I is for industrial customers; and Rate T is for transportation customers downstream of the city-gate.
[1232] ATM Initial Brief at 76-77.
[1233] ATM Initial Brief at 76-77.
[1234] ATM Initial Brief at 76-77.
[1235] ATM Initial Brief at 77; ATM Exhibit 2 at 5-6.
[1236] ATM Initial Brief at 78.
[1237] Brazos Initial Closing Statement at 3.

relative rate of return and not be charged more than their respective cost of service.[1238]

City of Dallas's Position

Dallas argues that TXU's proposed system-wide rates should be rejected.[1239] Dallas argues that the proposed system-wide rates result in more litigation expense, do not result in bills with greater transparency or simplicity, and have no effect on economic development with respect to municipalities.[1240]

Dallas argues that the Dallas system is an independent gas system with unique cost structures and should be entitled to separate rates to reflect the costs associated with gas service within the Dallas system.[1241] Dallas argues that system-wide rates amount to a $12 million subsidy by Dallas ratepayers to customers receiving gas service on other parts of TXU's system.[1242]

Industrial Gas Users' Position

IGU supports TXU's proposed system-wide rates as a logical and reasonable approach to prevent "a patchwork of inconsistent rates that would be confusing and potentially discriminatory."[1243] IGU's position is that TXU's proposal to bundle pipeline and distribution rates is not reasonable, sends inappropriate price signals and is anti-competitive.[1244] IGU argues that the Commission should set separate TXU Gas Distribution and Lone Star Pipe Line rates in this proceeding and order TXU to prepare a separate, unbundled cost-of-service study.[1245] IGU argues that bundled rates force industrial customers to pay for transportation service as part of their distribution service and therefore an industrial customer would effectively be prevented from choosing other transportation service if available. IGU further argues that TXU's proposal to limit rate increases to no more than 10% per customer class and deny any rate decrease is unreasonable and discriminatory.[1246]

State of Texas's Position

The State of Texas opposes TXU's proposed rate design and argues that TXU's 10% limit on rate increases is unreasonable and unfairly impacts industrial class customers.[1247] Texas proposes that the rate increase for residential class customers be increased to 12.67% to allow for reasonable rates that do not violate §104.003.[1248]

Examiners' Recommendation

The Examiners recommend the Commission approve TXU's proposal to limit all rate increases to 10%. Such a policy is reasonable and prevents rate shock. Most of the argument and testimony that opposes such a policy focuses on ending class subsidies and moving rates towards equalized relative rates of return. The calculation of cross-class subsidization is determined by how system costs are allocated among customer

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[1238] Brazos Initial Closing Statement at 5.
[1239] Dallas Closing Argument at 60.
[1240] Dallas Closing Argument at 61.
[1241] Dallas Closing Argument at 61-65.
[1242] Dallas Closing Argument at 61-65.
[1243] IGU Initial Brief at 24.
[1244] IGU Initial Brief at 24.
[1245] IGU Initial Brief at 24.
[1246] IGU Initial Brief at 25.
[1247] State of Texas Closing Argument and Brief at 7-12.
[1248] State of Texas Closing Argument and Brief at 12.

classes – an inherently subjective process. The degree to which rates reflect equal relative rates of return is a policy issue that the Commission must decide. The Examiners recommend the Commission adopt TXU's proposal to gradually move rates for all customers classes towards equal relative rates of return. However, the Examiners recommend that the Commission approach this goal gradually and limit rate increases per customer class to no more than 10%, as proposed by TXU.

A fundamental policy issue the Commission must decide concerns TXU's proposal to have its rates set on a system-wide basis. In the past, the Commission has set a system-wide city-gate rate on TXU Gas' pipeline system. Municipalities have set rates within their jurisdiction. Recently, municipalities approved rates for TXU in eight regions across the state. TXU argues that rates set on a system-wide basis will offer several benefits to customers and the company. GURA does not prohibit a system-wide filing by TXU. Although GURA contemplates a bifurcated regulatory scheme with regulatory oversight vested in the Commission and municipalities, the filing and consolidation of a statement of intent under the original jurisdiction of the Commission with appeals of the actions of municipalities is not prohibited by GURA.

TXU primarily argues that the advantages of system-wide rates are economic. While this proceeding has no doubt been long, complex, and expensive, the Examiners find it a difficult prospect to accept that the alternative to system-wide rates – the utility having a myriad number of rates, tariffs, and corresponding rate cases – is more efficient and less costly. Dallas argues that it is entitled to be treated as a separate and independent system for rate making purposes. However, the weight of the evidence does not indicate that Dallas is a separate and distinct utility system with unique costs that mandate consideration apart from the remainder of TXU's system. The Examiners therefore recommend the Commission approve and set distribution rates on a system-wide basis for TXU.

Another fundamental policy issue the Commission must decide concerns TXU's proposal to charge "bundled" rates. TXU's proposal is essentially one rate for all service – from wellhead to burner-tip. There have been numerous objections to TXU's proposed bundled rate structure throughout this proceeding. GURA does not expressly require a separate city-gate rate for transmission service that ends at the jurisdictional boundaries of a municipality. Thus, GURA does not expressly prohibit TXU's proposal to bundle its pipeline and distribution costs into a single rate for gas service.

The primary concern of the parties, and of the Examiners, with the proposed "bundled" rate is that it impedes regulatory examination at the municipal and Commission level. TXU did not provide a separate customer charge and volumetric rate for pipeline service that is simply added to the customer charge and volumetric rate for distribution service. Rather, TXU incorporated its pipeline cost of service into the distribution cost of service to calculate "bundled" rates. This makes the analysis and review of the proposed rates – by a municipality regarding rates over which it has jurisdiction – unnecessarily complex and burdensome. Given that rate proceedings under GURA have statutory deadlines, sound rate-making policy would disfavor rate structures that are unnecessarily complex and hinder timely review within the legally allotted period.

"Bundling" transmission costs with distribution costs contradicts TXU's proposed functionalization of its system into separate and distinct costs for transmission and distribution. "Bundling" transmission costs with distribution costs does not result in more transparent rates because regulators and customers are not easily able to discern these distinct types of costs from rates for gas service. Further, bundling transportation rates with distribution rates may be anti-competitive with respect to industrial transportation customers downstream of the city-gate. If rates are bundled, an industrial transportation customer that has alternative transmission choices would not likely choose an alternative shipper because that customer has already paid for pipeline transmission service. In such a scenario, the bundled rate captures industrial transportation customers and forces them to pay for TXU pipeline transmission services.

TXU has not met its burden of proof of establishing that "bundled" rates are just, reasonable, conform with sound rate-making policy, and allow for clear regulatory oversight at the municipal level and Commission. The Examiners recommend the Commission reject TXU's proposed "bundled" rate design and set separate rates for distribution and pipeline service.

B. Pipeline System Rates

TXU proposes two rates for its pipeline system, City Gate Service ("Rate CGS") and Pipeline Transportation ("Rate PT").

TXU's Position for Rate CGS

TXU proposes Rate CGS for service to the point of delivery of a distribution system. City Gate Service is generally firm service.[1249] TXU has proposed two classes of service for Rate CGS – Bulk Transmission and Network Transmission. Additionally, TXU proposes monthly, hourly and daily imbalance fees, an operational flow order imbalance fee, and a curtailment overpull fee for Rate CGS. The curtailment overpull fee would be charged to industrial and city-gate customers in the event that they utilize gas above the stated level of curtailment. The imbalance fees are incurred in the event a customer incurs gas imbalances in excess of gas volumes nominated. The following table summarizes the meter charge, capacity rate and volumetric rate for Rate CGS.

Table 11.1 Rate CGS

	Bulk Transmission	**Network Transmission**	**Distribution System**
Meter	$200 per meter	$200 per meter	$200 per meter
Capacity	$ 0.2710 per MDU	$ 1.0405 per MDU	$ 1.0405 per MDU
All MMBtu	$ 0.0795 per MMBtu	$ 0.2182 per MMBtu	$ 0.7553 per MMBtu

TXU's Position for Rate PT

The proposed Pipeline Transportation Service constitutes gas delivery to entities connected to the pipeline system who have procured their own gas supplies and is provided on an interruptible basis.[1250] TXU has proposed two classes of service for Rate PT – Bulk Transmission and Network Transmission. Additionally, TXU proposes monthly, hourly and daily imbalance fees, an operational flow order imbalance fee, and a curtailment overpull fee for Rate PT. The following table summarizes the meter charge, capacity rate and volumetric rate for Rate PT.

[1249] TXU Exhibit 23 at 12-14.

[1250] TXU Exhibit 23 at 11.

Table 11.2 Rate PT

	Bulk Transmission	**Network Transmission**
Meter	$ 200 per meter	$ 200 per meter
Capacity	$ 0.3910 per MDU	$ 0.9160 per MDU
First 12 MMBtu per Billing MDU	$ 0.0770 per MMBtu	$ 0.1038 per MMBtu
All Additional MMBtu	$ 0.0700 per MMBtu	$ 0.0800 per MMBtu

Railroad Commission Staff's Position

Railroad Commission Staff argues that the proposed daily and hourly imbalance fees are only reasonable if real-time data is available to customers prior to the imposition of such fees.[1251] Staff argues that it would be premature to impose such fees until real-time data is available at a reasonable price.

Brazos Electric Power Cooperative's Position

Brazos argues that TXU's proposed pipeline transportation rates are unreasonable because TXU is over-recovering costs caused by transportation customers.[1252] Brazos' position is that pipeline transportation rates should be designed solely to recover the cost of service to pipeline transportation customers.[1253] Brazos also objects to TXU's proposed imbalance fees. Brazos argues that the proposed imbalance fees are not supported by any cost study and are in effect a subsidy of residential and commercial customers by transportation customers.[1254] Brazos argues that the imbalance fees are a penalty on transportation customers and beyond the statutory authority of the Commission.[1255] Brazos further argues that its gas nominations are determined pursuant to ERCOT requirements which are determined late in the day after gas markets and gas nomination deadlines have passed.[1256]

Chaparral Steel Midlothian's Position

Chaparral objects to TXU's proposed daily and hourly imbalance fees. Chaparral primarily objects on the basis that TXU "failed to show there is a need to implement a daily imbalance charge" and "presented no cost justification for imposing the fee and has submitted no studies supporting the extent, if any, to which the failure of a customer to in balance on a daily basis imposes unrecovered costs on the TXU system."[1257]

City of Garland / Garland Power and Light's Position

Garland argues that TXU's proposed Rate PT, Rate T, and Rider CT (for competitive transportation) are unreasonable and should be rejected by the Commission. Garland argues that TXU has failed to justify abandoning negotiating contracts for these services.[1258] Garland argues that electric generation customers

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[1251] Staff Closing Statement at 12.
[1252] Brazos' Initial Closing Statement at 7.
[1253] Brazos' Initial Closing Statement at 7.
[1254] Brazos' Initial Closing Statement at 10-11.
[1255] Brazos' Initial Closing Statement at 10-11.
[1256] Brazos' Initial Closing Statement at 13.
[1257] Chaparral Initial Post-Hearing Brief at 17.
[1258] Garland Closing State at 2-3.

(such as Garland) provide human needs services and should be allowed to negotiate competitive transportation contracts that recognize their unique character, large volumes, and contributions to the operation of pipeline and distribution systems.[1259] Garland also argues that the proposed Rates PT, T and Rider CT are anti-competitive and discriminatory because these rates benefit electric generation plants owned by TXU.[1260] Garland argues that TXU owns over half of the 27 electric generation customers of TXU Gas, that over 80 percent of TXU's affiliate owned electric generation customers receive alternative gas service from non-regulated TXU Fuel, and this may result in anti-competitive and discriminatory practices by TXU.[1261]

Garland also argues that TXU's proposals for imbalance fees are unjust and unreasonable.[1262] Garland argues that the proposed imbalance fees are unjust and unreasonable because they are not cost based.[1263] Essentially, Garland argues that the fees are exorbitant, TXU failed to quantify the costs associated with imbalances, and the data is not available for transportation customers to make nominations accurately and avoid penalties.[1264]

Industrial Gas Users' Position

IGU objects to TXU's proposed capacity charges for pipeline transportation customers.[1265] IGU argues that the proposed capacity charges are essentially demand costs that are typically collected solely from firm customers – customers who receive non-interruptible service pursuant to the Commission's curtailment order. IGU's position is that customers who receive interruptible service should not pay capacity charges because as interruptible customers they have no right to demand system capacity on a firm basis.[1266] IGU also objects to the imbalance fees, curtailment overpull fee, and operational flow order imbalance fee TXU proposes for pipeline transportation customers.[1267] IGU argues these fees are unreasonable because TXU's metering capability is deficient.[1268]

State of Texas' Position

The State of Texas opposes TXU's proposed hourly and daily imbalance fees.[1269] Texas argues that TXU failed to meet its burden of proof of establishing that the proposed hourly and daily imbalance fees are cost-based, necessary, feasible, and just and reasonable. Texas argues that TXU submitted no evidence of costs associated with imbalances or evidence of revenues that such fees would generate.[1270]

Examiners' Recommendation

As discussed in section X.A., the Examiners have recommended denial of TXU's proposed functionalization of its transmission system into bulk transmission and network transmission. TXU also

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[1259] Garland Closing State at 2-3.
[1260] Garland Closing State at 2-3.
[1261] Garland Closing State at 2-3.
[1262] Garland Closing State at 4-7.
[1263] Garland Closing State at 4-7.
[1264] Garland Closing State at 4-7.
[1265] IGU Initial Brief at 25-26.
[1266] IGU Initial Brief at 25-26.
[1267] IGU Initial Brief at 29-31.
[1268] IGU Initial Brief at 29-31.
[1269] State of Texas Closing Argument and Brief at 14-17.
[1270] State of Texas Closing Argument and Brief at 14-17.

proposed separate bulk transmission and network transmission rates for Rate CGS and Rate PT that were based on that additional functionalization of the transmission system. TXU did not submit sufficient evidence or justification to satisfy its burden of proof to establish that the proposed bulk transmission and network transmission rates are just and reasonable. TXU's proposed bulk/network distinction distorts cost allocation by increasing the allocation of costs to city-gate customers. Rates based on the proposed bulk/network division will disproportionately cause more costs to be incurred by city-gate customers. Further, the Commission denied a similar division of the pipeline system in GUD No. 8976. Therefore, the Examiners recommend that the Commission deny separate bulk and network transmission rates for Rates CGS and PT.

As another sub-rate in the proposed design of Rate CGS, TXU proposed a separate distribution system rate. TXU's proposed distribution sub-rate has the highest volumetric charge and the highest capacity charge under Rate CGS. TXU did not submit sufficient evidence, justification, or satisfy its burden of proof to establish that the proposed distribution system sub-rate is just and reasonable. The effect of the separate distribution sub-rate is that city-gate customers (ultimately distribution customers) are allocated disproportionately more costs and incur more expense for gas service than customers receiving city-gate service under the other proposed sub-rates. Therefore, the Examiners recommend that the Commission deny the distribution system sub-rate for Rate CGS. The Examiners recommend that the Commission establish a single City Gate Service Rate comprised of a meter charge, a capacity charge and a single block volumetric charge. The Examiners' recommended rates for City Gate Service are the following: $200.00 per meter charge, a capacity charge of $0.8137 per billing MDU, and a volumetric charge of $0.1697 per MMBtu.

TXU also proposed separate bulk transmission and network transmission sub-rates for its proposed Rate PT. As discussed above, TXU did not submit sufficient evidence, justification, or satisfy its burden of proof to establish that the proposed bulk transmission and network transmission sub-rates are just and reasonable. Therefore the Examiners recommend the Commission set a single Rate PT that is applicable to appropriately classified customers.

TXU's proposed Rate PT consists of a $200.00 per meter charge, a capacity charge, and two declining block rates. TXU has proposed capacity fees for the pipeline transmission rate. The primary argument against the capacity charge in Rate PT is that it is a charge for firm service and would be charged to interruptible customers. The Examiners find IGU's position persuasive. TXU has not provided sufficient evidence and justification to base a portion of Rate PT on capacity. In effect, the proposed capacity charge is a method of extracting an increased minimum payment from pipeline transportation customers in lieu of relying exclusively on volumetric rates. The Examiners therefore recommend the Commission not approve a capacity charge element in the rate design for Rate PT. The Examiners recommend the Commission set a single Rate PT to be comprised of a meter charge and two declining block rates. The Examiners' recommended rates for Pipeline Transportation service are the following: $200.00 per meter charge, and volumetric charges of $0.1544 per MMBtu for the first 12 MMBtu per Billing MDU, and $0.1389 per MMBtu for all additional MMBtu..

The proposed hourly and daily imbalance fees, and the operational flow order imbalance fee were contested by many of the parties. The primary objection of the parties, including Commission Staff, is that there is not sufficient data available on TXU's system and its customers to allow customers to adjust gas volumes in order to avoid imbalance fees on an hourly and daily basis. TXU argued and provided testimony that the underlying policy of such fees is to "incent" transmission customers to nominate gas accurately. In order to allow a transmission customer to adjust its nominations and avoid fees for imbalances, it is crucial that the customer have accurate and timely information upon which to act. The weight of the evidence indicates that such information is not currently available or usable on an hourly and daily basis. Therefore the Examiners recommend the Commission deny TXU's proposed hourly and daily imbalance fees, and the operational flow order (hourly) imbalance fee for City Gate Service (Rate CGS), Pipeline Transportation (Rate PT), and Distribution Transportation class customers (Rate T).

Upon review, the Examiners find that TXU's proposed curtailment overpull fee is reasonable and recommend adoption by the Commission. The curtailment overpull fee will be incurred in the event of a curtailment or interruption and the customer receives gas in excess of the stated level of curtailment or interruption. The proposed fee is 200% of the midpoint price for the Katy point listed in *Platts Gas Daily* published for the applicable gas day. Curtailments are rare. The fee will discourage the receipt of gas deliveries in excess of the stated level of curtailment and is therefore reasonable.

C. Distribution Rates

TXU's Position

TXU proposes four rates for its distribution system: Residential Sales ("Rate R"), Commercial Sales ("Rate C"), Industrial Sales ("Rate I"), and Transportation ("Rate T"). Residential Sales service is service to separately and individually metered individual private dwellings or apartments. TXU has proposed declining block rates for Rate R. The following table summarizes the proposed rates for Rate R.

Table 11.3 Residential Sales

Minimum Customer Charge	$12.00
0 Mcf to 3 Mcf	$ 1.4533 per Mcf
All additional Mcf	$ 1.2032 per Mcf

Mr. Goble testified on behalf of TXU that the proposed declining block rate structures, along with the monthly customer charge, are designed to collect more revenue in the initial usage blocks than in the tail blocks of the rates.[1271] He testified that customers benefit from this rate design because they will pay successively less for gas consumed during cold weather.[1272] Mr. Goble further testified TXU will benefit because more revenues are collected from the customer charge and initial block.[1273] Because of this front loading, the declining block rate is also intended to achieve revenue protection from consumption variances due to weather in lieu of a weather normalization adjustment clause.[1274]

[1271] TXU Exhibit 24 at 24.
[1272] TXU Exhibit 24 at 24.
[1273] TXU Exhibit 24 at 24.
[1274] TXU Exhibit 24 at 25.

Commercial Sales Service ("Rate C") is proposed as service to any customer with a North American Industry Classification System Code ("NAICSC") beginning with 11, 22 (excluding electric generation), 23, 41 - 46, 48, 49, 51 - 56, 61, 62, 71, 72, 81, or 91 - 93. Industrial customers using less than 3,000 Mcf are eligible for Commercial Sales Service. TXU proposes declining block rates for Rate C. Mr. Goble testified that TXU has expanded the middle volumetric block of its commercial service rate in order to recover a greater amount of revenue from that block. The purpose is to reduce TXU's business risk related to weather.[1275] The following table summarizes TXU's proposals for Rate C.

Table 11.4 Commercial Sales

Minimum Customer Charge	$ 20 per month
First 0 Mcf to 30 Mcf	$ 1.5327 per Mcf
Next 320 Mcf	$ 1.2827 per Mcf
All Additional Mcf	$ 1.0329 per Mcf

Industrial Sales Service ("Rate I") is proposed for customers with NAICSC beginning with 21, 22 (electric generation only), 31, 32 or 33. TXU proposes a curtailment overpull fee for Rate I. TXU proposes declining block rates for Rate. The following table summarizes TXU's proposed Rate I.

Table 11.5 Industrial Sales

Meter Charge	$ 150 per meter
First 0 MMBtu to 1,500 MMBtu	$ 0.7879 per MMBtu
Next 3,500 MMBtu	$ 0.6414 per MMBtu
Next 45,000 MMBtu	$ 0.4949 per MMBtu
All Additional MMBtu	$ 0.3485 per MMBtu

The Applicant's proposed Transportation Service is delivery service provided to large consumers directly connected to the TXU Distribution System who procure their own gas supplies.[1276] TXU proposes a curtailment overpull fee for Rate T. TXU proposes declining block rates for Rate T. TXU proposes hourly, daily, and monthly imbalance fees, an operational flow order imbalance fee, and a curtailment overpull fee for Rate T. The following table summarizes TXU's proposed Rate T.

[1275] TXU Exhibit 24 at 26.
[1276] TXU Exhibit 23 at 12.

Table 11.6 Transportation

Meter Charge	$ 150 per meter
First 0 MMBtu to 1,500 MMBtu	$ 0.7879 per MMBtu
Next 3,500 MMBtu	$ 0.6414 per MMBtu
Next 45,000 MMBtu	$ 0.4949 per MMBtu
All Additional MMBtu	$ 0.3485 per MMBtu

Allied Coalition of Cities' Position

ACC opposes TXU's proposed residential and commercial minimum customer charge increase and residential declining block rate structure.[1277] ACC argues that TXU's proposed residential minimum customer charge ($10.00) should be reduced to $7.00. ACC also argues that TXU's proposed commercial minimum customer charge ($20.00) should be reduced to $10.00.[1278] Steven Andersen testified on behalf of ACC that the minimum charge for commercial customers should be set below class average customer costs because a minimum charge designed to recover average customer costs would discriminate against small commercial customers.[1279] ACC also argues that the Commission should reject TXU's proposed declining block rates for residential service. ACC argues that declining block rates are unnecessarily complex, increase cross-subsidies within the residential class, and reduce the financial incentive to invest in more efficient appliances and heating equipment.[1280]

Association of TXU Municipalities' Position

ATM recommends the Commission deny TXU's proposed customer charge increase and deny the proposed declining block rate structure for residential customers.[1281] ATM witness Jeffrey Rudolph testified that the minimum customer charges for residential and commercial service should be limited to $7.00 and $14.00 respectively.[1282] He testified that the residential service rate should be a single block and seasonally differentiated with winter rates 15 cents per Mcf greater than summer rates.[1283] He also testified that the commercial service rate should be seasonally differentiated, with a constant summer rate and two winter blocks. Mr. Rudolph further testified that the first winter block should be 15 cents per Mcf higher than the summer block, and that the second winter block should equal the summer block.[1284] ATM argues that the Commission should only approve a three block structure for Commercial rates as is currently adopted. ATM argues that TXU's proposed declining block rate structure for residential rates results in customers paying "a lower average rate during high usage months than during warm temperature months."[1285] ATM recommends "an unbundled energy charge, that includes separate Mcf rates for pipeline and distribution

[1277] ACC Initial Brief at 158-9.
[1278] ACC Initial Brief at 158-9.
[1279] ACC Exhibit 61 at 41.
[1280] ACC Initial Brief at 158-9.
[1281] ATM Initial Brief at 81.
[1282] ATM Exhibit 121 at 25, 32.
[1283] ATM Exhibit 121 at 25, 33-45.
[1284] ATM Exhibit 121 at 25, 33-45.
[1285] ATM Initial Brief at 85-86.

service, and a flat energy charge that is seasonally differentiated."[1286] ATM argues that the increases in minimum customer charges proposed by TXU unfairly burden low-use and/or low-income ratepayers, promote inefficient energy consumption, and include many costs that do not fluctuate with the number of customers.[1287]

Dallas's Position

Dallas's position is that the Commission should reject TXU's proposed minimum customer charge and declining block rate design for residential customers.[1288] Essentially, Dallas argues that GURA §104.301 (the "GRIP" statute) increases the customer charge over time and that it is inappropriate to charge residential customers declining block rates.[1289]

Examiners' Analysis and Recommendation

TXU's proposed minimum customer charges were contested by many of the parties. TXU's proposed residential customer charge of $12.00 would increase the minimum customer charges approved in the previous eight region-wide cases[1290] between $3.50 to $5.00 per month (41% to71% increase). TXU's testimony, evidence, and argument is that the increased minimum customer charges are necessary to recover fixed, customer-related costs. The Examiners find that the weight of the evidence does not show it unreasonable to recover a large portion of fixed, customer-related costs through minimum customer charges. However, the Examiners' consider it unreasonable to increase the minimum customer charge for residential service by 41% to 71%. The Examiners recommend the Commission approve a minimum customer charge of $9.00 for residential service. This will increase the minimum customer charges approved in the previous eight region-wide cases $2 to $0.50 (28% to 6%, respectively).

TXU's proposed minimum customer charges for commercial customers were also contested by many of the parties. TXU's proposed commercial customer charge of $20.00 would increase the minimum customer charges approved in the previous eight region-wide cases[1291] between $5.25 to $8.00 per month (35% to 66% increase). The Examiners' opinion is that it is unreasonable to increase the minimum customer charge for commercial service by 35% to 66%. The Examiners recommend the Commission approve a minimum customer charge of $15.50 for commercial service. This will increase the minimum customer charges approved in the previous eight region-wide cases $3.50 to $0.75 (29% to 5%, respectively).

The parties did not contest the $150 per meter charge proposed by TXU for Rates I and T. The Examiners find that the weight of the evidence indicates that TXU's proposed $150 meter fee for Rates T and I are reasonable. The Examiners recommend the Commission adopt the $150 meter fee proposed by TXU for Rates I and T.

Many parties contested TXU's proposed declining block rates for residential service. The evidence submitted in this case shows that gas cost is the most significant portion of a residential customer bill that

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[1286] ATM Initial Brief at 85-86.
[1287] ATM Initial Brief at 85-86.
[1288] Dallas Closing Statement at 65.
[1289] Dallas Closing Statement at 65.
[1290] GUD Nos. 9353, 9361, 9365, 9366, 9370, 9376, 9377, 9379
[1291] GUD Nos. 9353, 9361, 9365, 9366, 9370, 9376, 9377, 9379

varies with volume. The effect that a declining block rate for residential service is likely to have is more theoretical and speculative and clearly not as significant as the effect gas cost has on residential class customers. The Examiners find that the weight of the evidence does not indicate TXU's proposed declining block rates for residential service to be unreasonable as argued by several intervenors. However, the Examiners recommend that the Commission adopt a single block volumetric rate for residential service to serve the policy goals of simplicity of rate design and bill comprehension. Further, because the Examiners recommend an increase in the minimum customer charge, more fixed costs and customer-related costs are recovered reducing the need to load the first volumetric block in order to recover more costs as TXU proposes. ATM recommended seasonally adjusted single block rates for residential customers. The Examiners do not recommend the Commission adopt seasonally adjusted rates as proposed by ATM for the following reasons: (1) seasonally adjusting rates is a more complex process; (2) ATM proposes rates higher in the winter when residential customers are likely to have higher gas bills due to increased consumption; and (3) the weight of the evidence does not establish that seasonally adjusted rates will lead to more efficient consumption by residential customers.

Objections were made to TXU's proposed "elongation" of the middle volumetric block for Commercial service. TXU submitted testimony that the first block captures average base load usage, the middle block recovers winter heating load and excess base load consumption, and the final block recovers the remaining load exceeding 350 Mcf per month.[1292] The weight of the evidence and testimony indicates that the proposed volumetric blocks for commercial service are reasonable. The Examiners therefore recommend the Commission adopt TXU's proposed volumetric rate structure for Commercial service.

The parties did not object to the volumetric rate structure proposed by TXU for Rates I and T. The weight of the evidence and testimony indicates that the proposed volumetric blocks for Industrial Sales service and Transportation service are reasonable. The Examiners therefore recommend the Commission adopt TXU's proposed volumetric rate structure for Industrial Sales service and Transportation service.

The Examiners recommend the Commission deny hourly and daily imbalance fees, operational overflow imbalance fees for Rates I and T. These fees require the timely access to accurate data in order to adjust gas deliveries. The evidence indicates that such data is not readily available to TXU's customers in such a manner that customers who may be charged with these fees are able to make timely decisions and prevent them. The Examiners recommend the Commission adopt the proposed curtailment overpull fee for Rates I and T.

D. Miscellaneous Service Charges

TXU's Position

TXU has proposed several increases in fees for miscellaneous services. In its Rate M - Miscellaneous Charges, TXU proposes several charges for miscellaneous services. The following table summarizes these proposals.

[1292] TXU Exhibit 39 at 65-67.

Rate — Miscellaneous Charges

Connection Charge: Connection charge for reconnecting gas service.	$65 during business hours $97 after business hours
Field Read of Meter: Read for change charge.	$19.00
Returned Check Charge:	$20.00
Charge for Installing and Maintaining an Excess Flow Valve	Actual Cost
Recovery of Connection Costs Associated with Certain Stand-By Gas Generators	Actual Cost
Charge for Temporary Discontinuance of Service - Residential: Temporary disconnect at customer request	$65
Charge for Temporary Discontinuance of Service - Non-Residential: Temporary disconnect at customer request	$107
Charge for Meter Testing: Incurred if performed more than once within previous four years	$15
Charge for Service Call: For customer related problems	$26 during business hours $40 after business hours
Tampering Charge:	$125

Mr. Goble testified on behalf of TXU regarding the proposals in Rate M.[1293] Mr. Goble testified that the increases in the connect/reconnect charge, the field read of meter charge and the returned check charge are necessary to more fully recover the costs of these services. Mr. Goble testified that TXU is proposing new charges: service call charge, meter tampering charge, and temporary discontinuance of service charge. He testified that the service call charge is cost based and designed to compensate TXU for time, labor and transportation.[1294] Mr. Goble testified that the temporary discontinuance of service charge is intended to recover lost customer charge revenue for customers who disconnect during the spring and reconnect during the winter to avoid minimum customer charges.[1295]

Allied Coalition of Cities' Position

ACC objects to the amounts of the fees proposed by TXU in Rate M. ACC argues that TXU has not justified the magnitude of the proposed increases.[1296] ACC recommends the following changes to TXU's proposed miscellaneous service charges:[1297] (1) Reduce proposed Connect Charges from $65.00 to $45.00; (2) Reduce proposed Service Call Charge from $26.00 to $15.00; (3) Reduce proposed Meter Read Charge from $19.00 to $15.00; (4) Reduce proposed Temporary Disconnect Charge from $65.00 to $45.00; (5)

1293 TXU Exhibit 24 at 26-28.
1294 TXU Exhibit 24 at 26-28.
1295 TXU Exhibit 24 at 26-28.
1296 ACC Initial Brief at 160-1.
1297 ACC Initial Brief at 159-163.

Eliminate proposed Meter Testing Charge of $15.00; and (6) Reduce proposed Tampering Charge from $125 to $110.

Association of TXU Municipalities' Position

ATM objects to the proposed temporary disconnect charge.[1298] ATM argues that Mr. Rudolph's testimony establishes a cost-based discontinuance charge of $4.25 per month for residential customers, $9.56 per month for commercial customers, or aggregate amounts of $23 and $52 for residential and commercial customers over a 5.33 month average disconnect time-frame.[1299] ATM argues that current reconnect charges capture costs associated with temporary disconnection of service seasonally.

Examiners' Recommendation

TXU proposed increases to existing service charges and additional service charges to prevent temporary disconnection of service to avoid minimum customer charges. After reviewing all the testimony, evidence, and argument, the Examiners find that the weight of the evidence shows that TXU's proposed Rate M to be cost-based and reasonable. The temporary disconnect charge is a reasonable means to discourage customers from avoiding minimum customer charges and free-riding fixed capacity costs seasonally. The Examiners recommend the Commission adopt Rate M as proposed by TXU.

E. Standard Contracts for Industrial and Transportation Customers

TXU's Position

In this docket, TXU has filed proposed standard agreements for service for Rates CGS, PT, and T. The standard agreements are contracts for transportation service and are what TXU proposes be entered into between TXU and its transportation and city-gate customers. Rate schedule 31 is TXU's proposed General Transportation Contract Terms and Conditions and includes the following sections: (1) Definitions; (2) Quantity; (3) Laws and Regulations; (4) Nominations; (5) Imbalances; (6) Rates; (7) Receipt Point(s) and Delivery Point(s); (8) Pressures at Points of Receipt and Delivery; (9) Measuring Equipment and Testing; (10) Measurements; (11) Quality; (12) Additional Facilities; (13) Taxes; (14) Billing, Accounting, and Reports; (15) Responsibility; (16) Title-Warranty & Indemnity; (17) Waiver of Breaches, Defaults, or Rights; (18) Remedy for Breach; (19) Force Majeure; and, (20) Miscellaneous. Rate schedule 32 is TXU's proposed City Gate Transportation Terms and Conditions and includes sections and subsections which concern the following: (1) Subject Matter; (2) Downstream responsibilities; (3) Transportation and Storage Capacity; and (4) Gas Supply Sourcing. Rate schedule 33 is TXU's proposed Pipeline/Distribution Transportation Terms and Conditions and includes sections and subsections which concern the following: (1) Subject Matter; (2) Priority of Service; (3) Plant Protection Service and Firm Electric Load Quantities.[1300] TXU proposes that its standard agreements for service be reviewed and approved by the Commission.

Railroad Commission Staff's Position

Staff argues that all of TXU's proposed Standard Agreements should be removed from the tariff filing and thus not approved by the Commission. Staff argues that no contract term or condition should be filed with

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[1298] ATM Initial Brief at 95.

[1299] ATM Initial Brief at 95.

[1300] TXU Exhibit 1, Volume 3 at 74-95.

the Commission in the form of a tariff. Staff essentially argues that the filing of such contracts would put an undue burden on the Commission to analyze, review, and enforce the contracts. Staff also argues that litigation before the Commission may increase because disputes over such agreements may require Complaints to be filed before the Commission.[1301]

Brazos Electric Power Cooperative's Position
Brazos argues that the historical practice of negotiating contracts with transportation customers is proper.[1302] Brazos also questions the legality of the Commission's authority to impose standardized agreements on an entire industry or customer class. Brazos argues that the Commission does not have the authority to adjudicate contract claims, and therefore should not require the adoption of contracts.[1303] Brazos argues that TXU's proposal would have the Commission inappropriately impose one-sided contract terms on transportation customers and prevent this class of customer from engaging in contract negotiation, mediation, arbitration, or litigation.[1304]

Chaparral Steel Midlothian's Position
Chaparral Steel is opposed to several terms and conditions that TXU has proposed in the standard agreements for transportation service.[1305] Chaparral proposes that meter tests be inserted into the standard terms and conditions. Chaparral proposes requiring TXU personnel to follow an industrial facility's safety protocols. Chaparral objects to TXU's proposals to limit its liability, deliver gas at TXU's discretion, and plant protection service. [1306]

Industrial Gas Users' Position
IGU argues that uniform standardized tariffs and agreements for gas service are necessary to prevent TXU from imposing one-sided terms and conditions on transportation customers.[1307] IGU objects to several proposed terms and conditions in TXU's proposed agreements. IGU argues that TXU's proposed limitations of liability are unreasonable.[1308] IGU argues that the general terms and conditions of TXU's proposed transportation contract are unreasonable.[1309] IGU argues that TXU's proposed plant protection fee is unreasonable and any amounts collected to date under it should be refunded pursuant to a Commission Order.[1310]

Examiners' Recommendation
TXU argues that Texas Utilities Code §104.253 allows a gas utility to file its proposed agreements.[1311] The Examiners agree with TXU that the Utility Code allows TXU to file agreements with the Commission. However, the Examiners agree with the recommendation of Staff and recommend the Commission not allow TXU to file its proposed agreements. TXU has not specifically addressed the legal effect of

[1301] Staff's Closing Argument at 5-6
[1302] Brazos' Closing Statement at 5-7.
[1303] Brazos' Closing Statement at 5-7.
[1304] Brazos' Closing Statement at 8.
[1305] Chaparral Steel's Initial Post Hearing Brief at 24-27.
[1306] Chaparral Steel's Initial Post Hearing Brief at 19-27.
[1307] IGU's Initial Brief at 26-29.
[1308] IGU's Initial Brief at 32-33.
[1309] IGU's Initial Brief at 33-35.
[1310] IGU's Initial Brief at 38-43.
[1311] TXU Initial Brief at 157.

Commission approval of its proposed contract terms. The legal effect of the Commission mandating terms and conditions relating to indemnity, waiver of liability, title to gas, force majeure, and other clauses governed by contract and/or property law principles is unclear. Given the fact that such clauses have historically been negotiated by parties as part of negotiating contracts for service, it would be a substantial change in Commission policy to use the Commission's jurisdiction and authority to impose the content of transportation contracts on transportation customers. The Examiners find it unreasonable to force such terms on transportation customers when the historical practice has involved negotiation of such terms. The weight of the evidence does not establish that TXU has met its burden of proof of establishing that its standard agreements for service are just and reasonable. The Examiners recommend the Commission deny TXU's proposed standard service agreements – rate schedules 28, 29, 30, 31, 32, and 33. If the Commission decides to include the standard service agreements in this docket, the Examiners recommend that TXU's proposed plant protection service fee be considered in GUD No. 9460 as part of TXU's proposed curtailment order.

F. Miscellaneous Service Rates: Rate ANS, Rider CT, Rider RA, Rider FF, Rider SUR, and Rider Tax

TXU's Position

TXU has proposed Rate ANS - Ancillary Services, which is applicable for agreements TXU enters to provide ancillary services to shippers, operators, gas marketers, and other types of customers. Rate ANS includes but is not limited to the following services: transportation for off-system customers; compression; parking, lending; storage; blending; pooling; hub services; facility construction and/or operation; and exchange services.

Rider FF - Franchise Fee Adjustment is TXU's proposed tariff for adjusting customers' bills for municipal franchise fees. Rider SUR - Surcharges is TXU's proposed tariff for surcharges that may be imposed on customers' bills. Rider CT - Competitive Transportation Service is TXU's proposed tariff for transportation service contracts. TXU proposes that Rider CT be applicable for situations where true competition for transportation service exists. Rider RA - Retention Adjustment is TXU's proposed tariff for retention adjustment for Rate CGS, PT, and T customers. Rider Tax - Tax Adjustment is TXU's proposed rider for adjusting all rates (R, C, I, T, CGS, and PT) for applicable taxes.

Railroad Commission Staff's Position

Commission Staff opposes the approval of the proposed tariff Rate ANS - Ancillary Services because the proposed tariff has no ascertainable rates for the services described. Staff argues that TXU should not be allowed to file a tariff until a specific rate for each service listed is set under GURA and Commission Rules.[1312]

Association of TXU Municipalities' Position

ATM's position is that the Commission should modify Rider CT to require TXU to only offer non-standard contracts within a certain pricing bandwidth.[1313] ATM's testimony and argument is that a pricing bandwidth is necessary to prevent TXU from charging something less than incremental costs so that

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[1312] Staff's Closing Argument at 5.

[1313] ATM Initial Brief at 96-101.

regulated customers do not subsidize lower rates for non-standard contract customers.[1314]

Industrial Gas Users' Position
IGU argues that proposed Rider RA is unreasonable. IGU recommends the Commission modify Rider RA to reflect retention levels of 0.82% for Rate PT and 2.53% for Rate T.[1315]

Examiners' Recommendation
The proposed tariff for Rate ANS contains no specific rates for the services listed. The fact that no rates are proposed is the basis for Staff's opposition to the tariff. TXU argues that the services listed are ones that are negotiated and thus the ultimate rates for the services will be determined when parties enter into an agreement with TXU. TXU states that rates will be filed with the Commission in accordance with the Commission's rules when contracts for such services are entered.[1316] The tariff in and of itself is little more than a cursory listing of services that the applicant may contract for with third parties. The Examiners find the tariff for Rate ANS to be just and reasonable. Given that TXU has stated it intends to follow all Commission reporting rules should the company enter into an agreement to provide services listed in Rate ANS, the Examiners find no basis to recommend denial and/or removal of the proposed tariff from this docket.

No party objected to Riders FF, SUR, and TAX. The Examiners' find that the evidence establishes Riders FF, SUR, and TAX are reasonable. The Examiners recommend the Commission approve Riders FF, SUR, and TAX as proposed by the utility.

ATM proposes a pricing bandwidth to prevent TXU from charging rates to competitive transportation customers below incremental costs of service. In effect, ATM wants the Commission to insure TXU does not subsidize below market contracts with revenues from non-competitive customers whose rates are set by the Commission. ATM's expert offered testimony regarding a proposed pricing bandwidth. However, the evidence does not indicate that TXU is likely or able to charge rates for competitive customers below the utility's incremental cost of service. The Examiners find that proposed Rider CT is just and reasonable and recommend the Commission approve it as proposed by the applicant.

IGU proposes a modification of Rider RA. TXU argues that IGU's proposal is not appropriate because it does not reflect appropriate LUG and retention factors. The Examiners have recommended the recovery of actual LUG in TXU's gas cost recovery, subject to review by the Commission. TXU's proposed RA is reasonable given the proposal to recover LUG through gas costs. The Examiners find that the weight of the evidence establishes that Rider RA is reasonable and recommend the Commission adopt it as proposed by the utility.

G. Rates for Incremental Costs

State of Texas' Position
The State of Texas proposes that state agency customers are entitled under the provisions of §104.201 of

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[1314] ATM Initial Brief at 96-101.
[1315] IGU Initial Brief at 31.
[1316] TXU Initial Brief at 167.

the Texas Utilities Code to rates for transportation service based on the "incremental cost" of providing that service.[1317] The State's expert witness, Kelso M. King, testified as to the different types of cost of service studies: embedded and incremental.[1318] Mr. King testified that the difference between an embedded cost-of-service study and an incremental cost-of-service study relates to the different costs measured. Embedded costs are the accounting costs on the utility's books during a test-year and incremental costs are the costs of the resources required to provide the last unit of production.[1319]

The State's argument is that state agencies are entitled to rates based solely on the costs incurred by transporting additional volumes of gas. The State argues that Tex. Util. Code Ann. § 104.201 was enacted in 1993 to specifically provide that transportation rates for State agencies should be based upon the "cost of providing the transportation service."[1320] The State argues that this language requires gas transportation rates based on incremental costs be set for state agencies.[1321] The State argues that TXU's incremental costs for state agencies are the following: (1) State agency commercial distribution customers is $0.0748 per MMBtu; (2) State agency industrial distribution customers is $0.0156 per MMBtu; and (3) State agency pipeline system customers is $0.00097 per MMBtu.[1322]

The State alternatively proposed, in the event the Commission does not use incremental costs to set rates for state agencies, that the Commission should set rates based on the embedded costs of the test year.[1323] The State argues that TXU's cost of service study establishes that the proposed pipeline transportation rate is 24.5% higher than its embedded cost of $0.0608 per Mcf and that the distribution transportation rate is 43% higher than its embedded cost of $0.3367 per Mcf.[1324]

TXU's Position

TXU argues that state agency customers are not entitled to rates based on TXU's incremental cost of service.[1325] TXU argues that the State's reliance on §104.201 is improper because this docket has been filed under §§104.101 – 104.111.[1326] TXU further argues that Commission precedent established in GUD No. 9291 that rates set under §104.201 are not required to be set on the incremental transportation expense of the utility.[1327]

Examiners' Recommendation

There are no statutory provisions within GURA that utilize incremental cost methodologies for setting gas utility rates. GURA contains statutory provisions establishing a rate-making methodology based on the embedded costs of the gas utility. The Examiners recommend that the State of Texas' proposal to have transportation rates set on incremental cost be rejected.

[1317] State of Texas Closing Argument and Brief at 3-7.
[1318] Texas Exhibit 132 at 31.
[1319] Texas Exhibit 132 at 31-35.
[1320] State of Texas Closing Argument and Brief at 3-7.
[1321] State of Texas Closing Argument and Brief at 3-7.
[1322] State of Texas Closing Argument and Brief at 5.
[1323] State of Texas Closing Argument and Brief at 6.
[1324] State of Texas Closing Argument and Brief at 6.
[1325] TXU Initial Brief at 171.
[1326] TXU Initial Brief at 171.
[1327] TXU Initial Brief at 171.

XII. CONCLUSION

TXU Gas requested a total revenue requirement of $1,029,162,347 for its overall Pipeline and Distribution systems, which is an increase of $68,641,862 over total present revenue of $960,520,485. For the reasons discussed in the preceding sections of this Proposal for Decision, the Examiners recommend that the Commission approve a total revenue requirement of $918,115,119, a decrease of $42,405,366 from total present revenue.

Respectfully submitted,

John Chakales	Michelle Lingo	Mark Evarts
Hearings Examiner	Hearing Examiner	Technical Examiner
Office of General Counsel	Office of General Counsel	Gas Services Division

XIII. PROPOSED ORDER

XIV. SCHEDULES

XV. ATTACHMENTS

B. Acronyms and Terms

A&G	ADMINISTRATIVE AND GENERAL COSTS
ACC	THE ALLIED COALITION OF CITIES (INTERVENING PARTY IN GUD 9400)
ADFIT	ACCUMULATED RESERVE FOR DEFERRED FEDERAL INCOME TAX
AGA	AMERICAN GAS ASSOCIATION
ALG	AVERAGE LIFE GROUP (DEPRECIATION METHOD)
APB 16	ACCOUNTING PRINCIPLES BOARD OPINION NO. 16 (RELATING TO BUSINESS COMBINATIONS)
APBO	ACCUMULATED POST-RETIREMENT BENEFIT OBLIGATION
ATM	ALLIANCE OF TXU MUNICIPALITIES (INTERVENING PARTY IN GUD 9400)
ATS	AUTOMATED TIME KEEPING SYSTEM
BRAZOS	BRAZOS ELECTRIC POWER (INTERVENING PARTY IN GUD 9400)
CAP	COMPETITIVE ACTION PLAN
CAPM	CAPITAL ASSET PRICING MODEL
CCA	CUSTOMER CARE ADVOCATES
CCNC	COMPLETED CONSTRUCTION NOT CLASSIFIED
CHAPARRAL	CHAPARRAL STEEL MIDLOTHIAN, L.P. (INTERVENING PARTY IN GUD 9400)
CIAF	CAPITAL INVESTMENT ADJUSTMENT FACTOR
CIS	CUSTOMER INFORMATION SYSTEM
COS	COST OF SERVICE
COSERV	COSERV GAS, LTD. (INTERVENING PARTY IN GUD 9400)
CPI	CONSUMER PRICE INDEX
CSR	CUSTOMER SERVICE REPRESENTATIVES
CTC	COMPETITION TRANSITION COST <u>OR</u> COMPETITION TRANSITION COMPLETION
CWC	CASH WORKING CAPITAL
CWIP	CONSTRUCTION WORK IN PROGRESS
DALLAS	THE CITY OF DALLAS (INTERVENING PARTY IN GUD 9400)
D&A	DEPRECIATION AND AMORTIZATION COMPENSATION
DCF	DISCOUNTED CASH FLOW
DEVON	DEVON GAS SERVICES, L.P. (INTERVENING PARTY IN GUD 9400)
DICP	DEFERRED INFORMATION SYSTEM
DOD	UNITED STATE DEPARTMENT OF DEFENSE (INTERVENING PARTY IN GUD 9400)
E&P	EXPLORATION AND PRODUCTION
EGCF	ESTIMATED GAS COST FACTOR
EPI	TXU PROCESSING, FORMERLY ENSERCH PROCESSING, INC.
ELG	EQUAL LIFE GROUP (DEPRECIATION METHOD)
ERP	ENHANCED RETIREMENT PLAN (1997 & 1999)
FASB	FINANCIAL ACCOUNTING STANDARDS BOARD (ESTABLISHED GAAP)
FERC	FEDERAL ENERGY REGULATORY COMMISSION
FIM	FINANCIAL INFORMATION MANAGEMENT
FIT	FEDERAL INCOME TAX
FOF	FINDING OF FACT
G&A	GENERAL AND ADMINISTRATIVE COSTS
GAAP	GENERALLY ACCEPTED ACCOUNTING PRINCIPLES
GCCF	GAS COST CORRECTION FACTOR

GCR	GAS COST RECOVERY
GCRF	GAS COST RECOVERY FACTOR
GDP	U.S. GROSS DOMESTIC PRODUCT
GLO	THE GENERAL LAND OFFICE OF TEXAS (INTERVENING PARTY IN GUD 9400)
GPL	GARLAND POWER & LIGHT COOPERATIVE, INC. (GPL)
GUD	GAS UTILITIES DOCKET, RAILROAD COMMISSION OF TEXAS
GURA	GAS UTILITY REGULATORY ACT, TEX. UTIL. CODE ANN. §§101.001-123.024 (VERNON 1998 and SUPP. 2004)
HDD	HEATING DEGREE DAY
HRIS	HUMAN RESOURCES INFORMATION SYSTEM
HWI	HANDY WHITMAN INDEX (FOR MEASURING RELATIVE COSTS OF MAIN CONSTRUCTION FOR DIFFERENT YEARS)
IGU	INDUSTRIAL GAS USERS (INTERVENING PARTY IN GUD 9400)
ITC	INVESTMENT TAX CREDIT
ITS	INVESTMENT TAX CREDITS
LDC	LOCAL DISTRIBUTION COMPANY
LEP	LINE EXTENSION POLICY
LIBOR	LONDON INNER BANK OFFERING RATE
LSG	LONE STAR GAS
LSP	TXU LONE STAR PIPELINE, A DIVISION OF TXU GAS COMPANY, FORMERLY KNOWN AS LONE STAR PIPELINE, A DIVISION OF ENSERCH CORPORATION IN GUD NO. 8664
LUG	LOST AND UNACCOUNTED FOR GAS
LEAD LAG	CASH WORKING CAPITAL ANALYSIS
MCF	THOUSAND CUBIC FEET
MDT	MOBILE DATA TERMINALS
MDU	MAXIMUM DAILY USAGE FOR THE MONTHS OF DECEMBER JANUARY, FEBRUARY, AND MARCH (4MDU)
MEPR	MODIFIED EARNINGS-PRICE RATIO
MGCA	MONTHLY GAS COST ADJUSTMENT CLAUSE
MRS	METER READING SERVICE
MTB	MARKET-TO-BOOK RATIO
MOODY’S	MOODY’S INVESTOR SERVICES (DEBT RATING)
NARUC	NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS
NOAA	NATIONAL OCEANIC AND ATMOSPHERIC ADMINISTRATION
NTSB	NATIONAL TRANSPORTATION SAFETY BOARD
O&M	OPERATION AND MAINTENANCE COSTS
OPEB	OTHER POST EMPLOYMENT BENEFITS SUCH AS POST RETIREMENT BENEFITS, HEALTHCARE, DENTAL INSURANCE, MEDICAL INSURANCE, LIFE INSURANCE
PEP	PERFORMANCE ENHANCEMENT PLAN
POLY 1 PIPE	3306 POLYETHYLENE PIPE, MADE OF TR-414 RESIN
PSI	POUNDS PER SQUARE INCH
PUCT	PUBLIC UTILITY COMMISSION OF TEXAS
RF	RECONCILIATION FACTOR
RFI	REQUEST FOR INFORMATION
ROR	RATE OF RETURN
RRC	RAILROAD COMMISSION OF TEXAS
R&C	RESIDENTIAL AND COMMERCIAL CUSTOMERS

SCP	SAFETY COMPLIANCE PROGRAM
S&P	STANDARD & POOR'S CORPORATION (DEBT RATING)
SCP	SAFETY COMPLIANCE PROGRAM
SEC	SECURITIES & EXCHANGE COMMISSION
SFAS	STATEMENT OF FINANCIAL ACCOUNTING STANDARDS
SFAS 106	STATEMENT OF FINANCIAL ACCOUNTING STANDARDS NO. 106 RELATING TO EMPLOYERS' ACCOUNTING FOR POST RETIREMENT BENEFITS OTHER THAN PENSIONS; AMENDED APB 6
SLA	SERVICE LEVEL AGREEMENT (AGREEMENT EFF. 1-1-2002 WHEREBY TXU ENERGY PROVIDES CUSTOMER SERVICES TO TXU DISTRIBUTION FOR BILLING, CUSTOMER INFO, BILL PRINTING AND MAILING, REMITTANCE PROCESSING, COLLECTIONS, AND REPORTING)
SOI	STATEMENT OF INTENT
STAFF	THE RAILROAD COMMISSION OF TEXAS (INTERVENING PARTY TO GUD 9400)
STATE	THE STATE OF TEXAS, ATTORNEY GENERAL'S OFFICE, CONSUMER AFFAIRS
T&D	TRANSMISSION AND DISTRIBUTION
TXU	TXU GAS COMPANY
VSP	VOLUNTARY SEVERANCE PLAN (1999)
WACOG	WEIGHTED AVERAGE COST OF GAS
WINS	WINNING INNOVATIVE SERVICES PROGRAM INITIATED BY TXU IN 2002 TO REVIEW TXU BUSINESS SERVICES; ANTICIPATED COMPLECTION OF PROGRAM IN 2005
WTG	WEST TEXAS GAS, INC. (INTERVENING PARTY IN GUD 9400)