10. EGS, as one of five wholly-owned operating subsidiaries of the Entergy Corporation, serves a 28,000 square-mile area stretching across 350 miles of Gulf Coast region from Baton Rouge, Louisiana, to within 50 miles of Austin, Texas

11. EGS's electric utility operations are approximately evenly divided between Texas and Louisiana, with the Company divided into two general customer-service regions as follows the Southwest Region, headquartered in Beaumont, Texas, and ranging from Somerville, Texas, to Jennings, Louisiana, and the Southern Region, headquartered in Baton Rouge, Louisiana, and ranging from Jennings to the Bogalusa District of the Louisiana Power & Light Company

12. Throughout its two customer-service regions, EGS provides electric utility service to over 595,000 customers.

13. EGS owns four fossil-fuel powered generating plants, including two in Texas and two in Louisiana. Approximately 44 percent, or 2,410 megawatts (MW) of EGS's total generating capacity is provided by its Texas power plants, which are located near Bridge City, Orange County, Texas (Sabine Station), and near Willis, Montgomery County, Texas (Lewis Creek Station).

14. EGS's Louisiana power plants provide the remaining 56 percent, or 3,076 MW of fossil fuel-powered generating capacity, and are located near St Gabriel, Iberville Parish, Louisiana (Willow Glen Station), and Westlake, Calcasieu Parish, Louisiana (Nelson Station)

15. All of EGS's Texas and Louisiana power plants, with the exception of Nelson Station, Unit 6, normally use natural gas as a base-load fuel Nelson Station, Unit 6, is a 550 MW coal-fired generating unit that has no natural gas fuel burning capability EGS owns approximately 70 percent, or 385 MW of Nelson Station, Unit 6 The remaining 30 percent, or 165 MW, of Nelson Station, Unit 6, is owned in part by the Sam Rayburn Municipal Power Agency

(SRMPA) (accounting for 20 percent or 110 (accounting for 10 percent or 55 MW).

16. EGS also owns 42 percent, or 227 N Cajun II, Unit 3, operated by the Cajun Electı near New Roads, in Pointe Coupee Parish, Lo

17. In addition to all of the foregoing gen in the River Bend Nuclear Station, a Boiling near St. Francisville, Louisiana.

18. The Entergy Corporation (Entergy) is headquartered in New Orleans, Louisiana.

19. Entergy's five wholly-owned opera Entergy-Gulf States, Inc., (EGS), Entergy Entergy-New Orleans, Inc. Collectively, the electric utility service to approximately 2.4 m

20. The Federal Energy Regulatory Comı Entergy, along with the corresponding Enterg January 1, 1994, in Opinion No. 385, *Enterg* 65 F.E.R.C. (CCH) Par. 61,332 (1993).

21. The Entergy System Agreement (ESA planning and operation of the Entergy Syst wholesale power transactions among the EOC the basis for equalizing, among the EOCs, the and operation of system facilities.

22. Entergy's System Operations Center (SOC) and Resource Planning Department are responsible for implementing the ESA. The SOC is responsible for billing the different EOCs in accordance with the six service schedules that make up the ESA, and the payments and receipts under those schedules are set forth for each EOC in the monthly Intra-System Bill (ISB)

23. The ESA was originally approved by the FERC in Opinion No. 234, *Middle South Energy, Inc.*, 31 F.E.R.C. (CCH) Par. 61,305 (1985), along with six service schedules as follows: MSS-1, Reserve Equalization; MSS-2, Transmission Equalization; MSS-3, Exchange of Electric Energy Among the Companies; MSS-4, Unit Power Purchases; MSS-5, Distribution of Revenue from Sales Made for the Joint Account of All the Companies; and MSS-6, Distribution of Operating Expenses of Systems Operations Center. Proposed Schedule MSS-7, Merger Fuel Protection Procedures, the so-called "fuel tracker," is pending but has not been finally approved by the FERC.

24. Schedule MSS-2 provides for transmission equalization payments to equalize the costs among the EOCs associated with Entergy's transmission grid. The payments under MSS-2 are calculated according to an FERC-approved formula.

25. Schedule MSS-3 determines the pricing and exchange of energy among the EOCs By approving Schedule MSS-3, the FERC has determined how the EOCs will be reimbursed for energy sold to the exchange energy pool and how that energy is to be purchased.

26. Under Schedule MSS-3, if an EOC such as EGS supplies EGS-generated energy to the pool, the supplying Company receives an Operations & Maintenance (O&M) adder, the purpose of which is to reimburse the EOC for the incremental costs associated with making the sale to the exchange energy pool. This FERC-approved O&M adder is not reflected in fuel costs and is separate and distinct from the off-system sales adder referenced in Commission Preliminary Order Issue No. 9.

27. In contrast, when an EOC makes energy that was purchased outside the Entergy operating system available to the pool, it is reimbursed only for the costs of the energy under Schedule MSS-3.

28. Schedule MSS-5 addresses the net balance from energy sales made to companies other than EOCs for the joint accounts of all EOCs ("Joint Account Sales") The net balance is calculated by deducting any costs associated with Joint Account Sales from the gross revenues received for the sales, and is then distributed among the EOCs in proportion to each EOC's "Responsibility Ratio."

29. According to the ESA, an EOC's "Responsibility Ratio" is its own load responsibility divided by the system load responsibility, which is the average of the previous 12-months hourly loads coincident with the system's monthly peak hourly load

30. During January through August 1994, EGS experienced significantly higher natural gas prices than the $1.85 per MMBtu forecasted price upon which EGS's fixed fuel factors in effect during the reconciliation period were based.

31. During the first eight months of the reconciliation period, EGS's actual system-weighted average natural gas prices ranged from $1.95 to $2 86 per MMBtu During that time, EGS's under-recovered fuel balance, including interest, increased to $27,564,084, but then decreased to $22,375,752 through June 30, 1995, with the decline in natural gas prices

32. Because of the size of the under-recovery and its projection that it would continue to operate in a state of material under collection, in September 1994, EGS filed with the Commission an application styled: *Application of Gulf States Utility Company to Surcharge a Cumulative Under-Collection of Fuel and Purchased Power Costs*, Docket No 13409, 20 P.U.C. BULL. 686 (Jan. 18, 1995) (mem.). Docket No 13409 was resolved by stipulation

33. The Commission's Order in Docket No. 13409 directed EGS to reconcile, in calendar year 1995, its fuel and purchased power costs from January 1, 1994, and for the next twelve months thereafter. EGS filed the instant application on December 7, 1995, in compliance with the Commission's Order.

34. During the merger proceedings in Docket No. 11292, EGS and Entergy predicted merger-related fuel savings of approximately $40.5 million on a systemwide basis, of which approximately $35 million, or 86.4 percent, represents EGS's Texas jurisdictional share of the projected merger-related fuel savings.

35. In actual fact, EGS experienced merger-related fuel savings of approximately $12 million in 1994 and $9.6 million in 1995, or approximately $21.6 million on an Entergy systemwide basis, of which approximately $9.6 million is EGS's Texas jurisdictional share.

36. EGS's actual merger-related fuel savings were not as high as Entergy and EGS projected in the merger proceedings due to the cumulative effect of natural gas price volatility during the reconciliation period and due to the inputs into EGS's "PROMOD" computer model used to project merger-related fuel savings.

37. EGS's Texas jurisdictional share, or $9.6 million, of the merger-related fuel savings is reasonable, given the actual data inputs available to EGS to make the PROMOD runs and the volatile natural gas prices during the reconciliation period.

38. EGS's fuel factors set in Docket No. 10894 were not based on the merger forecast gas prices or other assumptions, but proved to be set too low based on a forecasted gas price of $1.76/MMBtu, since gas prices during the first eight months of the reconciliation period ranged from $1.95/MMBtu to $2.86/MMBtu.

39. In Docket No. 12712, EGS's fuel factors were again revised effective in March 1994 to approximate a gas price of $1.85/MMBtu, but gas prices did not decline to that level until September 1994, further contributing to an increase in EGS's fuel cost under-recovery.

40. EGS's recoverable fuel expense during the reconciliation period was approximately $59.1 million higher, or $22.9 million higher on a Texas jurisdictional basis, in 1994 than was recovered through EGS's fixed fuel factors approved in Docket No. 12712.

41. Therefore, there is no correlation between the amount of EGS's fuel cost under-recovery during the reconciliation period and its projected merger-related fuel savings, because the under-recovery was a function of EGS's fixed fuel factors, which were set too low in relation to highly volatile commodity gas prices.

42. Because there is no correlation between the level of EGS's merger-related fuel savings and the amount of its fuel-cost under-recovery during the reconciliation period, it would not be appropriate to offset EGS's fuel-cost under-recovery by any short-fall in projected merger-related fuel savings.

43. EGS's Texas retail fixed-fuel-factor customers receive merger-related fuel savings through EGS's fixed-fuel-factor and its impact on their monthly bills, because EGS's merger-related fuel savings are embedded in EGS's reconcilable fuel and purchased power costs.

44. Whether EGS's Texas retail customers paying the fixed fuel factor received a proportionate share of EGS's merger-related fuel savings depends on how EGS allocates fuel costs to its Texas retail fixed-fuel-factor ratepayers.

45. To the extent that EGS's fuel costs are lower than they would have been had the merger with Entergy not occurred, this fuel cost reduction would be passed through to EGS's customers on a proportionate basis if EGS allocated fuel costs on a proportionate basis.

46. EGS's Texas retail customers did not receive their fair share of the merger-related fuel savings because EGS does not allocate fuel costs to its fixed-fuel-factor customers in proportion to the fuel costs actually incurred to serve each customer

47. Entergy's systemwide merger-related fuel savings are not explicitly allocated to its customers since these savings are embedded in fuel costs, some of which may have decreased as a result of the merger. A correct, proportionate allocation of fuel costs to EGS's Texas retail fixed-fuel-factor customers should result in those customers receiving a proportionate share of EGS's merger-related fuel savings.

48. EGS's fuel costs are allocated to its Texas retail fixed-fuel-factor customers based on the ratio of Texas fixed-fuel-factor kWh sales at the plant to EGS adjusted system kWh sales (the "Texas Retail Allocator"), with the non-fixed-fuel-factor customers' kWh sales deducted from denominator of the Texas Retail Allocator. EGS also deducts all non-fixed-fuel-factor customer sales from its calculation of its adjusted system expenses, thereby removing these customers from the fuel cost allocation altogether.

49. Because there is an average fuel cost per kWh which represents the fuel cost any customer imposes on the EGS system whether or not that customer is billed for fuel on the basis of incremental or average fuel cost, EGS's fuel cost allocation methodology does not proportionately allocate fuel costs or merger-related fuel savings to Texas retail fixed-fuel-factor customers on a consistent basis because it does not account for all fixed- and non-fixed-fuel-factor customers' usage.

50. The fuel cost allocation methodology proposed by Commission Staff allocates to the Texas retail fixed fuel factor customers their proportionate share of fuel costs, based on the fuel costs EGS actually incurs to serve each type of customer

51. The net effect of the Commission Staff's fuel cost allocation methodology is that a slightly lower, more proportionate share of EGS's systemwide fuel costs are allocated to EGS's Texas retail fixed-fuel-factor customers than under EGS's methodology.

52. EGS allocates system fuel costs differently among its Texas retail fixed-fuel-factor customers and its special rate, non-fixed-fuel-factor customers, depending on whether the energy charge on the tariff schedule for the non-fixed-fuel-factor customers is based on system "average fuel cost," or whether it is based on "incremental fuel cost."

53. If the energy charge on the tariff schedule for a special rate, non-fixed-fuel-factor customer is based on systemwide average fuel cost, then the kWh sales and expenses incurred to serve that customer class are not subtracted by EGS in its fuel cost allocation methodology to account for these customers' fuel costs.

54. Conversely, if the energy charge on the tariff schedule for a special rate, non-fixed-fuel-factor customer is based on system incremental fuel cost, then EGS subtracts the kWh sales and expenses incurred to serve that customer class from its fuel cost allocation methodology, i.e., EGS removes their usage and expenses from the fuel cost allocator utilized to impute or determine the fuel costs for EGS's customers.

55. EGS currently has six special rate schedules which do not use a fixed fuel factor to recover fuel expenses. Because these six special rate schedules are non-cost-based discount rates, there is no requirement in the tariffs that they recover costs through a fuel factor. Some of the special rate schedules are incentive rates and some are experimental.

56. The fuel charge on a EGS special rate customer's tariff does not necessarily equate to the fuel expense incurred by EGS to serve that customer. EGS's incentive and experimental rates are not necessarily based on cost causality.

57. Because EGS's fuel cost allocation methodology does not proportionately allocate fuel costs to its Texas retail fixed-fuel-factor customers and non-fixed-fuel-factor customers on a consistent basis, the fuel costs incurred by special rate, non-fixed-fuel-factor customers were subsidized by the fixed-fuel-factor customer class in any given month of the reconciliation period, depending on whether EGS's system average fuel costs were greater than or less than its system incremental fuel costs.

58. During the reconciliation period, EGS's fixed- and non-fixed-fuel-factor customers actually experienced cross-subsidies of each others' fuel costs from month-to-month. The cross-subsidies during the reconciliation period almost canceled each other out, with the difference amounting to approximately $50,000. However, the absolute magnitude of the monthly cross-subsidies or cost-shifting during the reconciliation period amounted to approximately $900,000.

59. As discussed at Section VIII of the PFD, the appropriate fuel cost allocation methodology in this case requires that EGS include fuel costs imposed on the system by non-fixed-fuel-factor customers in both the Texas Retail Allocator and in the EGS System Adjusted Expenses variables of the allocator, regardless of whether those customers' fuel costs are priced on a system incremental cost basis. This fuel cost allocation methodology thereby ensures that fuel costs are allocated proportionately to both fixed- and non-fixed-fuel-factor customers based on actual cost incurrence and that each class of customers bears its proportionate share of EGS's fuel costs. Because this fuel cost allocation methodology is based on actual fuel cost incurrence, it will also eliminate the month-to-month cost shifting or cross-subsidization that occurred between EGS's fixed- and non-fixed-fuel-factor customers during the reconciliation period.

59A. EGS serves Texas retail customers that are not charged the fixed fuel factor, and these customers do not automatically receive the benefit of a fuel cost disallowance that is flowed through to customers via the fixed fuel factor. It is appropriate to include all Texas retail energy sales–both fixed fuel factor and non-fixed fuel factor–in allocating the systemwide fuel cost disallowance to the Texas retail jurisdiction.

59B. In allocating the Texas retail disallowance among Texas retail fixed- and non-fixed fuel factor customers, it is reasonable to credit certain incremental cost-based non-fixed fuel factor customers (*Rates SUS, SMQ and EAPS*) only for natural gas-related disallowances, with the remaining Texas retail disallowances otherwise allocable to those customers (*i.e* , nuclear, purchased power, coal and fuel oil) flowing to the Texas retail fixed-fuel factor customers

60. EGS did not present sufficient evidence in support of its proposed fuel cost allocation methodology to account for the fact that there is an average fuel cost per kWh which represents the fuel cost any customer imposes on EGS's system, whether or not that customer is billed for fuel on the basis of system incremental fuel cost or average fuel cost

61. During the reconciliation period, EGS's primary fuel was natural gas EGS had a total, before any disallowances, of approximately $589,573,767, of eligible natural gas expense during the reconciliation period.

62. EGS purchased approximately 44 percent of its natural gas through long-term contracts and acquired the remaining 56 percent through short-term purchases during the reconciliation period.

63. The factors most affecting EGS's natural gas costs during the reconciliation period included the role of natural gas in EGS's capacity and energy mix and the relevant markets in which the Company purchased its gas. Natural gas accounted for approximately 50 percent of EGS's energy mix during the reconciliation period

64. EGS's long-term natural gas contracts provided for EGS's relatively extensive "swing" requirements during the reconciliation period EGS's natural gas consumption during the reconciliation period generally followed the instantaneous energy demand of its customers EGS's natural gas supplies must therefore be reliable and available in adequate volumes and in flexible ways to provide for the changes EGS experienced in instantaneous customer demand for electricity during the reconciliation period.

65. The FERC's natural gas transportation open access and unbundling initiatives promoted the development of a commodity-driven, short-term gas market during the reconciliation period. The FERC's unbundling initiative meant that full-service gas transportation services were disaggregated into gathering, transportation, imbalance control, flexibility, and storage services, with separate charges for each individual service. The impact of these developments on EGS during the reconciliation period resulted in an operational need to negotiate separate contracts for highly reliable and flexible natural gas swing services. Open access also resulted in a more competitive short-term gas market.

66. EGS's short-term gas supply purchasing strategy predicts the volume of gas to be purchased during "bid-week." Bid-week is the formalized period immediately preceding the operational month during which gas suppliers and gas purchasers conduct monthly gas supply transactions and when monthly pipeline nominations must be made.

67. Although EGS attempts to purchase the bulk of its short-term natural gas during bid-week, in reality, during the reconciliation period, EGS had to purchase as much as 30 percent of its short-term gas needs as daily or after-market gas at or near the end of the month.

68. EGS's long-term natural gas supply contracts included the Pontchartrain and Spindletop Gas Distribution System (SGDS) agreements, which were both signed in 1984 and amended in 1991. The high degree of flexibility, reliability, and swing provided by the Pontchartrain and SGDS contracts gave EGS the ability to maximize its purchasing activities in the short-term gas market by purchasing base-load, interruptible short-term gas with the assurance that it could still meet its swing requirements.

69. Both agreements contain supplier's Weighted Average Cost of Gas (WACOG) pricing mechanisms, plus a seller's margin pricing mechanism of $0.31 per MMBtu. The supplier's WACOG price term is capped by a gas market index and a fuel oil alternative price ceiling, giving the seller an incentive to offer EGS competitive long-term gas prices.

70. EGS's natural gas acquisition strategy of maximizing its spot gas purchases permits it to take advantage of a swing transportation agreement with Sabine Gas Transmission Company (SGT) and the capacity in the Spindletop Storage Facility. On August 1, 1991, EGS entered into an agreement with SGT whereby SGT has the responsibility of providing EGS with natural gas transportation services, delayed transportation services, swing service, and storage capacity in the Spindletop natural gas storage facility in return for a transportation fee.

71. SGT's legal right to market unused capacity in the Spindletop storage facility is limited by the agreement, pursuant to which EGS has first priority on capacity and deliverability of natural gas. SGT must obtain prior approval from EGS before entering into any third-party transactions.

72. Although EGS may release unused capacity in Spindletop back to SGT for marketing to third parties, all net revenues, defined as revenues less electricity, operations, and maintenance expenses, from third-party transactions must be immediately credited to reduce the "pay-off amount" owed by EGS to SGT as long as the pay-off amount is greater than zero, under the terms of the agreement.

73. Because the pay-off amount under the SGT agreement was greater than zero during the reconciliation period, EGS did not directly receive any of the revenues from third-party transactions in excess capacity in the Spindletop storage facility during the reconciliation period.

74. During the reconciliation period, SGT received approximately $488,602.15 in third-party net revenues attributable to third-party transactions in the Spindletop storage facility. After the reconciliation period, SGT received an additional $47,973.32 in net revenues from third-party transactions also conducted during the reconciliation period, for total reconciliation period third-party revenues of $536,575.47.

75. The value to third parties of the excess capacity in SGT's Spindletop storage facility during the reconciliation period was greatly diminished due to (1) the limited amount of excess capacity available after EGS's requirements were met; (2) the period when excess storage was available for released to third parties; and (3) the geographic proximity of the Spindletop storage facility to major gas marketing centers.

76. There was very little excess capacity available for third-party transactions in the Spindletop natural gas storage facility during the reconciliation period. EGS needed approximately 1,000,000 MMBtu of working gas capacity in Spindletop during the reconciliation period for operational purposes and maintenance of system flexibility and reliability alone. EGS needed between 1,500,000 MMBtu and 1,700,000 MMBtu of additional capacity for seasonal price arbitrage during the fall and winter months of the reconciliation period.

77. During the reconciliation period, third-party utilization of Spindletop accounted for only about 15 percent of the injections and 19 percent of withdrawals.

78. EGS did permit SGT to market excess capacity in Spindletop to Koch, Centana, and Eastex Gas Marketing Companies during the reconciliation period.

79. EGS's offset, through SGT, of the pay-off amount with net third-party revenues from the marketing of excess capacity in Spindletop during the reconciliation period was reasonable, because EGS will likely require additional storage capacity in Spindletop in the future and that capacity will enable EGS to reduce its reliance on more expensive long-term and spot natural gas.

80. EGS's efforts to market excess capacity in the SGT Spindletop natural gas storage facility during the reconciliation period were reasonable, to the extent any excess capacity existed after EGS's requirements were met and in light of the greatly diminished value of such services to third parties.

81. EGS had to purchase a significant amount of its short-term gas on a daily and weekly basis after bid-week in response to changes in its system operational conditions during the reconciliation period, including changing customer demand for electricity, unanticipated changes in the availability of off-system economy energy, fuel supply and transportation constraints, and compliance with interstate pipeline tariffs and rules.

82. On average, during the reconciliation period, EGS purchased approximately thirty percent of its monthly short-term gas supplies after bid-week. The amount of short-term gas EGS purchased daily during the reconciliation period varied significantly during the reconciliation period, based on the bidders' anticipation of market changes and EGS's anticipation of market changes and variations in the short-term market.

83. Deleted.

83A. EGS did not provide sufficient evidence to meet its burden of proof in justifying its level of short-term natural gas expenditures during the reconciliation period. Furthermore, EGS's rebuttal testimony relating to the Cities' proposed disallowance of short-term natural gas expenditures is incomplete.

84. Deleted.

84A. The limited evidence presented by EGS relating to its short-term natural gas contracts is insufficient to allow the Commission to determine whether individual short-term natural gas purchasing decisions were prudent. Therefore, EGS has not met its burden of proof with respect to its short-term natural gas expenditures and the preponderance of the evidence favors the adoption of the Cities' proposed disallowance of $3,473,207 on a systemwide basis.

85. Although there was no reason for EGS to burn fuel oil instead of natural gas at EGS's Willow Glen Station in March 1994 because there was no gas curtailment at that time and the

generating unit would have been derated, EGS had nevertheless burned fuel oil at the Willow Glen Station generating units at or very near to the time of the March 1994 spot natural gas purchases from Koch and Pontchartrain.

86. Entergy and EGS therefore could have made the switch from natural gas to fuel oil at Willow Glen in March of 1994 and knew or should have known that the price differential existed, making fuel oil the more economical fuel to burn.

87. $62,958 represents the difference between the price of natural gas and fuel oil at Willow Glen Station in March 1994, based on the number of MMBtu used, and therefore this natural gas fuel expense was unreasonably incurred and should be disallowed.

88. The inventory price for No. 6 fuel oil at Willow Glen Station in March 1994 was $2.3145/MMBtu, and the price of spot natural gas was $2.42/MMBtu and $2.60/MMBtu, depending on the supplier.

89. EGS purchased 48,732 MMBtu of natural gas from Koch Gas Services Co. at $2.42/MMBtu and 136,327 from Pontchartrain Natural Gas System at $2.60/MMBtu in March 1994.

90. The total MMBtu available from No. 6 fuel oil at Willow Glen Station in March 1994 was equivalent to the total 185,059 MMBtu of natural gas purchased at the higher price.

91. A motion for sanctions is required to : (1) contain all of the factual allegations necessary to apprise the parties of the conduct at issue; (2) request specific relief; and (3) be verified by affidavit. P.U.C. PROC. R. 22.161(e).

92. The request for imposition of sanctions filed by General Counsel with its Initial Closing Brief does not contain the level of factual allegations necessary to apprise the parties of the conduct alleged to be at issue on the part of EGS because it is not clearly stated and it is not

verified by sworn affidavit. In any event, a hearing must be held before a ruling on a motion for sanctions can be made, provided the motion is properly before the Commission in accordance with P.U.C. PROC. R. 22.161(e).

93. EGS's long-term Pontchartrain natural gas swing contract was effective on November 1, 1991, and was subject to review by the Commission in a previous fuel reconciliation in Docket No. 13170, *Application of Gulf States Utilities Company to Reconcile Fuel Costs,* 20 P.U.C. BULL. 1026 (April 18, 1995) (Conclusion of Law No. 6).

94. Docket No. 13170 was a stipulated or settled fuel proceeding, and the doctrine of collateral estoppel or "issue preclusion" applies to facts that were fully and fairly litigated in the prior action.

95. The reasonableness of EGS's Pontchartrain long-term natural gas swing contract was not fully and fairly litigated in Docket No. 13170 because that docket was stipulated and the agreement specifically reserved agreed issues for consideration in future proceedings. EGS was a party to the agreement.

96. EGS entered into the Pontchartrain and Spindletop Gas Distribution System (SGDS) long-term natural gas contracts in 1984 after an earlier long-term agreement with Exxon USA became less economical. These identical contracts are reasonable and are based on the seller's WACOG plus a margin of $0.31/MMBtu.

97. The Pontchartrain and SGDS long-term gas supply agreements provide EGS with a high degree of flexibility and reliability because they allow significant long-term gas supplies to be shifted between EGS's Willow Glen Station, which is located in Louisiana, and it Texas power plants. The seller's margin of $0.31/MMBtu reasonably accounts for the high degree of swing and flexibility in these contracts.

98. At the time EGS entered into the Pontchartrain and SGDS long-term agreements, the seller's WACOG was an appropriate and reasonable measure of pricing for long-term natural gas used in the industry. The SGDS contract was only recently changed to an index when it was renegotiated in 1994 at the new supplier's request for deliveries through a different pipeline.

99. The use of a published index, plus a margin of $0.15/MMBtu, as a standard of review for EGS's Pontchartrain and SGDS long-term natural gas contracts does not reflect the circumstances in existence at the time the contracts were entered into and accordingly it is not a reasonable standard by which to assess the reasonableness of the contracts' price terms.

100. A margin of $0.15/MMBtu, as proposed by Cities, does not account for the degree of swing and flexibility in EGS's long-term contracts with Pontchartrain and SGDS.

101. EGS had approximately $94,552,504 in total eligible coal costs during the reconciliation period.

102. Of its total eligible coal costs, roughly two-thirds or $60,845,303 of EGS's coal costs were attributable to coal burned at EGS's Nelson Station, Unit 6, a coal-fired generating unit. The remainder of $33,707,201 in EGS's eligible coal costs were attributable to Big Cajun II, Unit 3, coal and displaced power costs.

103. The coal for EGS's coal-fired generating units is supplied under a long-term contract with Kerr-McGee Corporation (Kerr-McGee) from its mines in Wyoming. EGS also purchased approximately 7,884 tons of spot coal from Kerr-McGee during the reconciliation period for its Nelson Station, Unit 6 generating unit.

104. EGS is also a party to a long-term transportation agreement with the Burlington Northern and the Kansas City Southern Railroads for delivery of the coal from Kerr-McGee's mines to EGS's coal-fired generating plants. Neither of these long-term transportation agreements was amended during the reconciliation period.

105. EGS purchased coal for its Big Cajun II, Unit 3, (Big Cajun) generating station under a long-term contract with the Triton Coal Company (Triton). The coal was transported to the Big Cajun station by rail and barge transportation during the reconciliation period.

106. EGS owns 42 percent of Big Cajun II, Unit 3, which is operated and owned in part by the Cajun Electric Power Cooperative, Inc., (CEPCO). EGS's 42 percent share accounts for approximately 227 MW of the total 540 MW rated generating capacity of Big Cajun II, Unit 3. CEPCO's remaining 58 percent share accounts for 313 MW.

107. On January 1, 1995, EGS changed its coal inventory accounting methodology from last in, first out, (LIFO) to the average cost method. EGS made this change to be consistent with Entergy's inventory accounting valuation methodology.

108. As a result of EGS's change to the average cost method, the value of EGS's coal inventory decreased by $996,109. The corresponding decrease in EGS's revenue requirement is a net reduction in Texas retail base rate revenues of $56,787.

109. EGS's change in coal inventory accounting methodology from LIFO to average cost resulted in fuel savings during the reconciliation period because the prices EGS paid for coal purchased during the first six months of 1995 were higher than the average price of all of the coal in its inventory.

110. Under the LIFO method, the cost of coal in EGS's inventory reflects the market price of coal. In contrast, under the average cost accounting method, the cost of the less expensive coal purchased by EGS in previous years and still in inventory decreases the overall average cost of the inventoried coal burned at EGS's power plants during the reconciliation period.

111. Therefore, the change in coal inventory accounting methodology from LIFO to average cost method did not have a significant adverse impact on ratepayers, but likely lowered the coal

costs they would have otherwise paid during the reconciliation period, had the change in inventory accounting valuation methods not been made.

112. In October 1994, CEPCO advised EGS that CEPCO had expended all available funds for operating CEPCO's 30 percent share of the River Bend Nuclear Station (River Bend). CEPCO therefore advised that it would not make any further payments to EGS in 1994 for River Bend's operations, maintenance, or capital expenses.

113. Consequently, EGS ceased providing all power to CEPCO from River Bend and informed CEPCO that it would: (1) credit EGS's share of the expenses attributable to Big Cajun II, Unit 3, against amounts that CEPCO owed to EGS for operation of River Bend; and (2) seek to market CEPCO's share of the power from River Bend and apply the proceeds from that power against amounts that CEPCO owed to EGS.

114. Therefore, from November 2 through December 19, 1994, (the "displacement period"), CEPCO refused to provide EGS with EGS's share of the power from Big Cajun II, Unit 3.

115. Because CEPCO withheld EGS's share of power from Big Cajun II, Unit 3, during the displacement period, EGS replaced the energy which would have been generated by Big Cajun II, Unit 3, with more expensive energy, specifically purchased power and power from the other EOCs ("replacement power").

116. Instead of including the cost of this "replacement power" in its reconcilable fuel costs, EGS computed reconcilable fuel costs for the displacement period as if Big Cajun II, Unit 3 had continued to supply energy to EGS and as if the replacement power had not been purchased. This displaced cost adjustment represents the difference between the more expensive replacement power and an estimate of what the power from Big Cajun II, Unit 3, would have cost EGS's ratepayers if it had been operated during the displacement period.

117. In September 1994, EGS made an incorrect calculation, inflating the coal costs preceding the displacement period for Big Cajun II, Unit 3, and amounting to approximately $225,583 on a total company basis, or $90,653 on a Texas jurisdictional basis, meaning that EGS's coal costs should be adjusted downward by $90,653.

118. Had EGS calculated reconcilable coal costs for September 1994 utilizing the correct tonnage of coal actually burned at Big Cajun II, Unit 3, the total reconcilable coal costs for that month would have been $2,368,985 for coal stock purchases and transportation, instead of $2,594,568 which EGS requested. The difference is approximately $225,583 on a total company basis, or $90,653 on a Texas jurisdictional basis.

119. In making its displaced cost adjustment calculation to account for the cost of the replacement power for Big Cajun II, Unit 3, EGS relied on questionable coal inventory data provided by CEPCO, failed to take into account the effect of prior month true-ups, and did not adjust for a 50,000 ton coal inventory adjustment made by CEPCO; EGS's displaced cost adjustment calculation of the coal costs attributable to the pseudo-burn at Big Cajun II, Unit 3 was therefore based on unsound data.

120. In light of the fact that Big Cajun II, Unit 3, did not actually generate power for EGS during the displacement period, it was not possible for EGS to accurately predict what the heat rate and unit efficiency of Big Cajun II, Unit 3, would have been in order to accurately calculate the displaced power cost adjustment for the reconciliation period.

121. Because it was not possible to accurately predict what the heat rate or unit efficiency would have been for Big Cajun II, Unit 3, during the displacement period had it provided EGS's share of the output, the best cost estimate available is the price of power EGS relied upon in deciding whether or not to schedule power from Big Cajun II, Unit 3.

122. The replacement power costs for Big Cajun II, Unit 3, can best be calculated utilizing an approximate cost of $15/MWh, which is the cost EGS's own dispatchers use in determining

whether or not to schedule power from Big Cajun II, Unit 3 This cost is very close if not essentially the same as the $14.85/MWh cost of coal EGS utilized in its PROMOD computer runs to estimate the merger-related fuel savings for the reconciliation period

123. Calculating the costs of generation or replacement power for Big Cajun II, Unit 3, during the displacement period based on a cost of $14 85/MWh, with 95 27 percent of that cost as reconcilable cost, results in a reconcilable cost of replacement power at Big Cajun II, Unit 3, of $14.15/MWh.

124. Therefore, $14.15/MWh is the cost that should be utilized to calculate the cost to EGS of replacement power for Big Cajun II, Unit 3, during the displacement period

125. EGS had 255,300 MWh of displaced or replacement power at Big Cajun II, Unit 3, during the displacement period, resulting in reconcilable cost of generation for the reconciliation period of $3,612,495 ($14.15/MWh x 255,300 MWh = $3,612,495), which is $704,608 less, on a total company basis, than the $4,317,103 EGS charged or requested for this item in its application.

126. The foregoing methodology is an appropriate methodology of calculating the cost of replacement power for Big Cajun II, Unit 3, under the circumstances and eliminates the uncertainties and inaccuracies posed by EGS's methodology, which places too much reliance on unsound data from CEPCO's coal inventory and the unknown heat rate of the units at Big Cajun II.

127. Application of the foregoing methodology results in a reduction of $584,046 in reconcilable coal costs for EGS on a total company basis, or $226,447, with interest, on a Texas jurisdictional basis.

128. EGS's portion of the long-term coal consumed at Big Cajun during the reconciliation period was 1,599,232 tons or 25,943,427 MMBtu, representing total reconcilable coal expenses of $33,707,201.

129. The long-term coal supply for EGS's share of Big Cajun was purchased by CEPCO in conjunction with the Western Fuel Association (WFA). EGS's long-term coal expenses for its share of Big Cajun of $33,707,201, subject to any disallowances for the cost adjustments for Big Cajun II, Unit 3 during the displacement period, were reasonable.

130. EGS's portion of the long-term coal purchases at Nelson Unit 6 accounted for 2,383,251 tons or 40,231,501 MMBtu for the reconciliation period, representing total reasonable reconcilable long-term coal expenses of $60,812,584.

131. In December 1994, EGS purchased 7,884 tons of spot coal from Kerr-McGee for its Nelson Unit 6 at a price of $4.15/ton or $0.2413/MMBtu. Under the terms of the spot-coal letter agreement, Kerr-McGee agreed to deliver up to 150,000 tons of coal at the $4.15/ton price.

132. EGS did not seek bids from any coal suppliers other than Kerr-McGee for the December 1994 spot-coal purchase, relying instead on a reported spot bid of $4.43/ton for 1995 deliveries of coal to the Lower Colorado River Authority (LCRA) and because the Kerr-McGee bid was lower than the LCRA's.

133. EGS could have obtained a lower bid for spot-coal in December 1994 if it had solicited bids from other Wyoming coal producers. The October 3, 1994 issue of *Coal Week* reported that Grand Island Nebraska purchased spot coal from the Caballo Rojo Mine for $4.05/ton or $0.2411/MMBtu. Additionally, for October, November, and December 1994, *Coal Week* also reported that the marker price for 8,400 Btu/lb. coal from Wyoming was $4.05/ton.

134. EGS was not prudent in its decision to purchase the spot coal from Kerr-McGee in December 1994 without bidding and should have solicited bids from all of the coal suppliers served by the Burlington Northern Railroad in Wyoming and taken the lowest bid.

135. EGS's December 1994 spot-coal purchase for Nelson Unit 6 should have reflected the lower market prices at the time of the purchase. The market price for the total 7,884 ton spot-coal purchase for Nelson Unit 6 during the reconciliation period was $31,930.20, at a price of $4.05/ton. EGS paid approximately $32,719 for the spot-coal from Kerr-McGee at a price of $4.15/ton, or approximately $788 more than it should have paid for the spot coal at the time.

136. EGS did not include any expenses of the Nelson Rail Spur, a rail spur that is being constructed to its Nelson Station. EGS originally intended to complete the spur in 1995, but delayed its completion because it believed that the lower transportation rate to justify the construction of the spur was not available from the railroad companies.

137. Although EGS never received the equivalent of written bids containing rates used to justify the construction expense of the Nelson rail spur, it received verbal assurances from railroads that deliveries could be made over the Union Pacific/Southern Pacific railroads at a substantial savings over existing rates.

138. EGS's use of an estimated transportation rate during the reconciliation period to justify a several million dollar rail spur is not prudent management. Unless and until EGS shows complete and credible documentation that the rail spur is a benefit to EGS's ratepayers, EGS should not include any of the expenses in its fuel reconciliation or future rate proceedings.

139. EGS burned approximately 221,192 barrels of fuel oil or the equivalent of 1,396,899 MMBtu during the reconciliation period, resulting in total reconcilable fuel oil expenses of $4,028,017.

140. EGS burns small amounts of No. 2 fu
Cajun II, Unit 3, power plants for start-up anc
contingency supplies of No. 6 fuel oil in i
Stations in the event of gas curtailments durin

141. EGS purchased its fuel oil during th
approved qualified bidder's list. Accord
$4,028,017 for the reconciliation period were

142. EGS owns 70 percent of the River I
(GE) designed Boiling Water Reactor (BWR
Louisiana, which is approximately 24 miles n
remaining 30 percent share in RBNS. The p
the merger of EGS with Entergy.

143. RBNS achieved commercial operatior
at a capacity of 2,984 MWh, with its turbi
electric).

144. Although RBNS' performance during
based on its heat rate, capacity factor, and fc
Entergy's long-term goal of placing RBNS
nuclear power plants resulted in a sub
reconciliation period.

145. RBNS' comparatively poor performar
extended forced outage (FO-94-02) whic
approximately 42.7 days.

146. The uranium (U3O8) utilized as nucl was purchased primarily under long-term coı fuel-grade uranium was in short supply and th

147. EGS made the purchases of the urani other nuclear fuel cycle services, on behalf oi these nuclear fuel contracts and expenses reasonable in Docket No. 10894.

148. The parties in that proceeding are ider of the reasonableness of EGS's nuclear fu contracts was fully and fairly litigated. Docl reconciliation.

149. With the exception of reactor operati costs of RBNS nuclear fuel as a total dire capitalizes financing costs of the nuclear fue reactor core.

150. During the operation of the reactor during the reconciliation period include: (1) t financing costs; and (3) spent fuel expense.

151. A typical fuel cycle for RBNS is a period for a refueling outage. Therefore, a ty 16 months of operation and a two-month refu

152. The nuclear reactor at RBNS requir support an 18 month fuel cycle, which repre fuel in the reactor.

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153. Each reload of the nuclear fuel typically remains in the reactor at RBNS for three fuel cycles. Therefore, the reactor refueling is staggered so that approximately one-third of the nuclear fuel is replaced each fuel cycle.

154. The uranium purchased by EGS pursuant to contracts entered into in the mid-1970s was used in the reactor core at RBNS from the time it achieved commercial operation, up to the present.

155. The 1970s uranium purchased by EGS for RBNS has now all been loaded into the reactor core and will be completely used over the next two refueling cycles, refueling cycles 6 (RF-6) and 7 (RF-7).

156. EGS did not solicit bids for the uranium enrichment services for RBNS because at the time, all U.S. suppliers had to contract with the United States Government for these services. Nevertheless, EGS achieved the prevailing market prices for its later uranium purchases and conversion services through operation of the competitive bidding process.

157. EGS's uranium, conversion, enrichment, and fabrication contracts were reasonable and consistent with the purchasing practices of other utilities for other U.S. nuclear facilities at the time, both in terms of price and contract specifics.

158. In 1990, at a time when uranium prices were relatively low, EGS purchased significant quantities of uranium in the spot market to complete the uranium requirements for RBNS refueling outage number 4 (RF-4) in April 1992.

159. By the end of 1990, EGS signed two additional separate uranium contracts to meet the uranium requirements for RBNS into the late 1990s. The suppliers were Uranerz Exploration and Mining (Uranerz) and RTZ Mineral Services (RTZ). EGS awarded these contracts to Uranerz and RTZ after the solicitation and receipt of favorable bids from these suppliers.

160. The relatively high cost of the nuclear fuel at RBNS incurred by EGS during the reconciliation period was due to the fact that the uranium was purchased under long-term contracts entered into in the mid-1970s when uranium prices were high.

161. Although EGS placed less expensive uranium into the core-in-service at RBNS during refueling outage number 5 (RF-5), the core-in-service during the reconciliation period still contained significant amounts of the expensive 1970s uranium from refueling outage number 3 (RF-3) and refueling outage number 4 (RF-4).

162. On a total percentage basis, from April 1994 through January 1996, the core-in-service at RBNS still contained approximately 52.5 percent of expensive 1970s uranium.

163. EGS's nuclear fuel costs for RBNS during the reconciliation period were nevertheless reasonable, because prior to and during the reconciliation period EGS and Entergy management made reasonable choices from among the range of alternatives available and in light of the information on nuclear fuel supplies and prices at the time.

164. EGS's uranium, conversion, enrichment, and fabrication contracts were well managed by EGS and Entergy and were consistent in terms and cost with the contracts and contemporaneous industry procurement practices at the time. Therefore, EGS's nuclear procurement prices and overall nuclear fuel costs were reasonable during the reconciliation period.

165. EGS's U.S. Department of Energy (DOE) nuclear Decontamination & Decommissioning (D&D) costs for RBNS during the reconciliation period were governed by Title XI of the National Energy Policy Act of 1992, which established a D&D fund with the U.S. Treasury and provided for annual deposits of $150,000,000 via a special assessment from domestic utilities.

166. Although neither EGS nor Entergy has sought or received a refund of D&D fees during the reconciliation period from the DOE, EGS made its last payment of the assessment "under

protest with full reservation of all rights to challenge the validity of the assessment and to seek a refund of the entire amount of the payment, with interest as allowed by law." This issue should be addressed in EGS's next fuel reconciliation case.

167. Refueling Outage five (RF-5) at RBNS began on April 15, 1994, and ended on July 6, 1994. EGS originally planned RF-5 to last 53 days, but the outage actually lasted 82 days.

168. EGS established major activities for RF-5 as follows: (1) replacement of approximately one-third of the used nuclear fuel assemblies; (2) motor-operated valve testing; (3) main turbine rotor replacement; (4) Residual Heat Removal (RHR) system repairs; (5) diesel generator maintenance; and (6) other modifications to existing plant systems to improve the material condition of the plant.

169. In general, the purpose of a nuclear refueling outage is to refuel the reactor by replacing approximately one-third of the nuclear fuel in the reactor core, make repairs or modifications to the plant that cannot reasonably be made while the plant is operating, and to correct problems that are identified for the first time during the outage.

170. The length of a nuclear refueling outage is determined from a management perspective by evaluating the tasks on the "critical path." of the outage.

171. The critical path for an outage is the series of the most lengthy tasks during an outage that cannot be performed simultaneously. The parallel work that would have become critical path to the refueling outage if the actual critical path activity had not occurred is known as near-critical-path activity.

172. Without reference to the specific tasks and the critical path activities of a refueling outage based on an analysis that centers on critical path activities, it is nearly impossible to make a decision whether or not a particular extension of an outage was the result of imprudent management.

173. The duration of RF-5 at RBNS during the reconciliation period was reasonable to the extent of 69.06 days and was prudently planned and managed to that extent

174. The duration of RF-5 was not reasonable to the extent of 12 94 days, due to EGS's failure to adequately plan and manage the reactor containment airlock work that was performed during the outage.

175. The cost of the replacement power attributable to the unreasonable 12 94 day extension of RF-5 is $1,830,569, based on the average cost of nuclear fuel at RBNS during the reconciliation period of $8.60/MWh. Therefore, $1,830,569 of EGS's fuel expenses attributable to the cost of the replacement power for the unreasonable extension of the duration of RF-5 by 12.94 days should be disallowed.

176. Forced Outage No. 94-01 (FO-94-01), or Outage No 94-03 at RBNS, occurred on September 8, 1994, when RBNS experienced a process water "noise spike" that was perceived by the reactor vessel water level transmitters as an improper or high reactor vessel water level The vessel water level transmitters sent a "scram signal" to the reactor protection system logic, which shut down the plant.

177. EGS replaced a leaking fuel rod assembly during forced outage FO-94-01 (outage no 94-03), and also repaired eight segments of Control Rod Drive (CRD) piping, one of which was found to be leaking. The outage lasted 42.7 days

178. The reactor vessel water level transmitter automatic shutdown feature at RBNS ensures that water will not enter the steam lines and eventually travel to the main turbine where the turbine blading could be damaged.

179. The actual source of the initiating event or noise spike causing forced outage FO-94-01 at RBNS was never identified, but all four of the reactor vessel water level transmitters responded to the event.

180. During RF-5, EGS installed Rosemount Model 1153 Transmitters to replace two of the four reactor vessel water level transmitters due to the degradation of the originally-installed Rosemount Model 1152 Transmitters. There was a need for the installation of a special "damping" card in the new Model 1153 transmitters to allow them to function like the original Model 1152 transmitters.

181. "Damping" on a reactor vessel water level transmitter serves to filter out spurious or background signals that do not represent actual vessel water conditions

182. EGS personnel installed one of the new Model 1153 transmitters without any damping card and the other transmitter contained a damping card with incorrect settings

183. Deleted.

183A. The evidence presented by the Cities demonstrates that the validity of EGS's after-the-fact calculation of the effect of the process noise on the improperly installed Rosemount Model 1153 transmitters is, at best, questionable; thus, EGS has not established that the transmitters were not the cause of FO-94-01.

183B. In its response to the NRC regarding FO-94-01, EGS concluded that the reasons for the violations were due to an "oversight on the part of engineering" and because "the maintenance planner did not properly plan the maintenance work order "

183C. EGS admitted in contemporaneous correspondence with the NRC that the reason for the spurious reactor trip on September 8, 1994 was because the improperly installed transmitters were overly sensitive to process noise.

183D. The problem with the Rosemount 1153 transmitters with little or no damping being susceptible to false indications due to process noise was identified as early as April 1988 when SIL 463 was issued.

183E. Given that EGS personnel installed the transmitters improperly, that there were known problems with the improperly installed transmitters, and that EGS did not establish that the improperly installed transmitters were not the cause of FO-94-01, it follows that the improperly installed transmitters were the cause of FO 94 01

183F. The improper installation of the Rosemount 1153 transmitters was due to imprudent management on the part of EGS. Therefore, the associated replacement power costs were not reasonable and necessary expenses, and a disallowance of $1,519,787 on a systemwide basis is appropriate.

184. Deleted.

185. Deleted.

186. Forced outage number FO-94-02, or outage number 94-04 at RBNS occurred on October 8, 1994, due to a failure of a recirculation pump seal which required a reactor shutdown for repairs. This forced outage lasted 5.8 days, ending on November 3, 1994

187. The failed recirculation pump seals at RBNS had been replaced prior to the forced outage with a new-type seal during an earlier refueling outage, RF-5 Before RF-5 at RBNS, the recirculation pump seals were replaced several times and the new design was an attempt by EGS to correct the performance problems encountered with the old design

188. The new recirculation pump seal design failed due to accelerated wear caused by particles in the reactor cooling water at RBNS

188A. EGS did not properly inform MPR about purge water quality data or the possibility of a crud burst occurring. Had the consultant been properly informed, MPR's report indicates that it would have recommended silicon carbide rather than the tungsten-carbide that eventually failed and caused forced outage FO-94-02.

188B. The risk assessment performed by EGS management for use of tungsten-carbide versus silicon carbide seals was not adequate because no criteria for particulate levels was defined by the vendor or asked for by design engineering

188C. A reasonable utility manager would have employed all relevant information available at the time in its assessment of the risk of using of tungsten-carbide versus silicon-carbide seals EGS failure to perform an adequate risk analysis constitutes imprudence

188D. Because forced outage FO-94-02 was the result of imprudent management on the part of EGS, the associated replacement power costs were not reasonable and necessary expenses Therefore, a disallowance of $545,548 on a systemwide basis is appropriate

189. Deleted.

190. Deleted.

191. A "crud burst" is a phenomenon that occurs in water systems due to particulate accumulation on the inside surfaces of water pipes during normal operation

192. Deleted.

193. Outage number 94-05 (forced outage number FO-94-03) occurred at RBNS on December 4, 1994, when a technician at the plant made a communication error which caused a

reactor trip or shutdown during the monthly testing of the Main Steam Isolation Valves (MSIVs). The outage lasted approximately 7.4 days, ending on December 12, 1994.

194. During the monthly testing of the MSIVs at RBNS, EGS technicians initiated a half isolation of the controls for the MSIVs. The MSIV test is designed such that only a single, one-half isolation is encountered at one time. Two concurrent one-half isolations will cause the closure of the MSIVs and a plant shutdown or reactor "scram."

195. During the MSIV testing at RBNS, one of the technicians performing the test misunderstood a communication in the control room to be an acknowledgment that a first one-half isolation signal had been reset, when in fact the communication concerned the reset of an alarm annunciator.

196. Upon hearing the control room alarm reset communication, the technician signed-off the reset procedure step and the test proceeded to the next section, which involved inserting the second half isolation in the plant logic at RBNS.

197. Because the first one-half isolation had never in fact been reset, the insertion of the second half isolation completed the logic for the closure of the MSIVs, causing a plant shutdown and forced outage number FO-94-03.

198. Deleted.

199. Deleted.

199A. A contributing cause to the human error causing forced outage FO-94-03 was the improper modification of verification step procedures by EGS management. By removing the verification procedures, EGS management set up an independent verification method that established a work practice that was, as stated by EGS, "less than adequate."

199B. The decision by EGS management to remove the verification procedure was not reasonable in light of the circumstances, information and options available at the time, and was therefore imprudent.

199C. The actions and decisions of EGS's technicians that led to forced outage FO-94-03 were controllable and/or affected by EGS management

199D. The ultimate performance of a utility's technicians is a function of the adequacy and reasonableness of the utility's management. With respect to FO-94-03, EGS's management was neither adequate nor reasonable because EGS management did not have in place the basic procedures or the necessary safeguards to prevent such a catastrophic event from occurring as the result of such a simple mistake.

199E. Because forced outage FO-94-03 was the result of imprudent management on the part of EGS, the associated replacement power costs were not reasonable and necessary expenses Therefore, a disallowance of $657,386 on a systemwide basis is appropriate

200. As a result of the operation of the ESA, EGS paid $36,936,199 02 to its affiliate Entergy operating companies (EOCs) for energy it received from the Entergy system energy exchange pool during the reconciliation period.

201. EGS's affiliate EOC purchased power expense represents 1,838,569 MWh of electricity it purchased from affiliate EOCs during the reconciliation period at an average cost of $20.09/MWh.

202. Schedule MSS-3 of the ESA determined the pricing and exchange of energy among EGS and the affiliate EOCs during the reconciliation period

203. By approving Schedule MSS-3 and the ESA, the Federal Energy Regulatory Commission (FERC) has determined how the EOCs will be reimbursed for energy sold to the exchange pool and how the EOCs, including EGS, will purchase energy from the exchange pool

204. When an EOC such as EGS supplies energy to the exchange pool that the EOC produced, it receives an Operations & Maintenance (O&M) adder, the purpose of which is to reimburse the producing EOC for the incremental cost associated with making the sale to the exchange pool

205. The EOC exchange pool affiliate transaction O&M adder is not reflected in EGS's fuel costs for the reconciliation period and is therefore not passed on to ratepayers in their fuel costs

206. EGS purchased power from its affiliate EOCs participating in the system exchange pool during the reconciliation period at an average price of $20 09/MWh and that price was no higher than the prices charged by the supplying EOC affiliates to the other EOCs or affiliates

207. The FERC has determined that the ESA and Schedule MSS-3 is a just and reasonable way of allocating energy costs and revenues among the EOCs, including EGS, and has determined that the charges imposed on EGS by operation of the ESA are fair and reasonable in comparison to the charges imposed on the other EOCs

208. Additionally, because the O&M adder for energy sales to the EOC energy exchange pool is not reflected in the EGS's fuel costs and does not include a profit, EGS's purchased power expenses of $36,936,199.02 for energy purchased from the system exchange pool during the reconciliation period were reasonable.

209. Although each EOC's allocation of energy costs and revenues under the ESA may vary based on its relative size and its operating characteristics, the ESA ensures that EGS is paying proportionately no more for purchased power through the ESA than any of its affiliates who are also parties to the agreement.

210. Schedule MSS-5 of the ESA provides that EGS is to be reimbursed for its cost of fuel to supply the pre-merger system power sales plus an O&M adder, but that EGS not share in the net revenue balance or profits from such sales. In its opinion and order approving the merger of Entergy and EGS, the FERC found good cause for limiting EGS's participation in the profits from off-system sales contracts in existence at the time of the merger.

211. The FERC approved the allocation of off-system sales O&M adders among EGS and the EOCs as set forth in Schedule MSS-5 of the ESA as reasonable. Although EGS did receive its share of net balance revenues from such sales made after the merger during the reconciliation period, EGS properly accounted for the differential in revenues received by EGS, as compared to the other EOCs.

212. The $1,189,982.80 System Fuels, Inc., fuel-oil purchase by EGS was reasonable because the $121.80 price per barrel was below the market price for fuel oil when compared to both the average and low spot market prices, according to *Platt's Oilgram*. The price for the fuel oil was no higher than the prices charged by System Fuels, Inc., to its other affiliates.

213. During the reconciliation period, EGS purchased all of Agrilectric Company's (Agrilectric) net energy output at a price of $35.42/MWh pursuant to a contract rate approved by the Louisiana Public Service Commission (LPSC). EGS purchased a total of $3,756,557.78 worth of purchased power from Agrilectric during the reconciliation period.

214. EGS's purchased power costs for its Agrilectric transactions during the reconciliation period were above EGS's avoided cost. Had Agrilectric been located in Texas rather than Louisiana, EGS would likely have paid for the purchased power in accordance with EGS's Texas tariff for Small Power Producers. The total purchase price for the Agrilectric power under that tariff would have been approximately $1,750,800.10, or approximately $2,005,756 less than EGS paid during the reconciliation period.

214A. EGS did not present sufficient evidence to show that it needed the capacity as required by P.U.C. SUBST. R. 23.66(d)(1)(D) when it renegotiated the Agrilectric contract in 1994

215. Because EGS was not obligated to purchase the Agrilectric power, the appropriate price ceiling is EGS's avoided cost, reflected by what EGS would have paid for the power had the Agrilectric power been purchased under EGS's Small Power Producer tariff Accordingly, EGS's expenditure of $2,005,756 above its avoided cost of $1,750,800 10 for the Agrilectric purchased power was unreasonable and excessive and should be disallowed

216. In the Preliminary Order in this docket, the Commission directed that the profit margins or "adders" from EGS's off-system power sales were, in their entirety, subject to a reasonableness review and reconciliation beginning April 28, 1994, through the end of the reconciliation period.

217. Pursuant to that Order, EGS is required to allocate 100 percent of its off-system sales adders as reconcilable beginning on April 28, 1994, the date of the final order in Docket No 12712.

218. The Commission's Final Order in Docket No 12712 did not explicitly continue the 75-25 percent split or sharing of the margins from EGS's off-system sales originally approved in Docket No. 10984. Therefore, no vested interest in a share of the off-system sales revenues or adders was conferred on EGS.

219. Although the interim fixed fuel factors in effect during the last portion of the reconciliation period were implemented by agreement of the parties on an interim basis in Docket No. 12712 beginning as early as March 1994, the Commission did not consider and finally approve those fuel factors until April 28,1994, the date the Final Order in that docket was signed.

220. The Commission Preliminary Order directed that EGS's off-system sales adder revenues should be allocated 100 percent to ratepayers as reconcilable beginning on April 28, 1994

221. EGS's total transmission or wheeling revenues which it received under transmission service contracts approved by the FERC between EGS and wholesale transmission customers ("Company Service") amounted to $42,007,597, on an Entergy systemwide basis, for the reconciliation period.

222. EGS's company service transmission or wheeling revenues are revenues which EGS received pursuant to contracts EGS entered into before the merger with Entergy Corporation Consequently, these revenues are not part of the Intra-System Bill (ISB) and are therefore not allocated to any of the other EOCs.

223. EGS's total transmission or wheeling revenues associated with FERC-regulated Entergy System transmission transactions under Entergy's open access transmission tariff ("Access Service") amounted to $1,501,687 during the reconciliation period Access service transmission or wheeling revenues are revenues EGS received through the Entergy system pool and were allocated to each of the EOCs including EGS, on a monthly basis by operation of the ISB under the FERC-approved ESA.

224. EGS had total transmission equalization expenses, which were charged to FERC Account 565 and which EGS incurs under Schedule MSS-2 of the ESA, amounting to $16,565,619 during the reconciliation period.

225. EGS's total net transmission or wheeling revenues for the reconciliation period, after deducting transmission equalization charges, amounted to approximately $26,943,665 on a total company basis, or approximately $11,000,000 on a Texas retail jurisdictional basis

226. Because EGS's transmission or wheeling revenues and costs were not allocated to Texas retail ratepayers during the reconciliation period, but were allocated to a separate rate class

specified by the Commission's Order in Docket No. 12852, EGS's last base rate case, Texas retail ratepayers should not benefit from an inclusion of EGS's net wheeling revenues in this fuel reconciliation proceeding.

227. EGS's SO2 emissions allowance revenues during the reconciliation period resulted from the EPA auction of withheld allowances first available for use in the years 2000-2001. EGS received approximately $50,000 from the auction of its SO2 emissions allowances during the reconciliation period.

228. EGS accounted for the SO2 emissions allowance revenues which it received during the reconciliation period in FERC Account 411.8, entitled "Gains from Disposition of Allowances," which is included as utility operating income in the Statement of Income for the Year in FERC Form 1 for 1994.

229. P.U.C. SUBST. R. 23.23 defines eligible fuel costs according to the FERC Uniform System of Accounts, as of September 30, 1992.

230. On March 31, 1993, the FERC issued Order No. 552, effective January 1, 1993, regarding "Revisions to Uniform System of Accounts to Account for Allowances under the Clean Air Act Amendments of 1990," expressly leaving the proper accounting treatment of revenues from SO2 emissions allowances to be determined by the state regulatory commissions.

231. Because the Commission has not expressly determined whether or not SO2 emission allowance revenues are reconcilable fuel revenues, EGS should record SO2 emission allowance revenues in FERC Account 254, rather than Account 411.8, so that both emissions revenues and costs may be considered by the Commission at a future date.

232. Because EGS's SO2 emission allowance revenues amounted to only $50,000 during the reconciliation period, the regulatory treatment of such revenues should not be decided on the merits due to the relatively small amount of such revenues in this reconciliation.

233. EGS's system electricity losses during the reconciliation period amounted to 2,543,009 MWh of electricity, out of a total 51,512,084 MWh of electricity produced During the reconciliation period, EGS identified and recovered approximately $1,000,000 in lost revenues due to equipment failure, process failure, and theft of electricity

234. EGS has in place adequate measures to address lost revenues attributable to theft of electricity and current diversion in its diverse, mainly rural service territories and its employees have been trained to investigate current diversion, take corrective action appropriate to the circumstances, and reasonably recover lost revenues during the reconciliation period

235. Deleted.

236. Deleted.

237. Deleted.

238. Deleted.

239. EGS adjusted its Generation Expenses & Purchased Power Expenses, resulting in net amounts for these downward adjustments of $17 and $12,022, respectively The foregoing adjustments are reasonable as timing adjustments to reflect actual costs and adjustments in the applicable months.

240. EGS made the refunds ordered in Docket No 13170, its last fuel reconciliation for the period October 1, 1991, through December 31, 1993, after December 31, 1994 EGS should have made these refunds to customers before December 31, 1994, because on January 1, 1995, interest on the refunded amounts began to accrue

241. In making the refunds ordered in Docket No 13170, EGS made an entry of $50,091 to reflect the interest associated with those refunds which was not correct because the actual refunds occurred over several months. Therefore, the $50,091 in interest recorded for the refunds should be deducted or removed.

242. As of October 31, 1994, EGS's ending balance of the refunds ordered in Docket No 10894 was under-recovered by ($779,971). EGS did not carry forward this refund balance from Docket No. 10894 and include the balance in the instant fuel proceeding, the next fuel reconciliation after Docket No. 13170, as required in Docket No 10894

243. EGS did not carry forward or transfer its $779,971 over-refund amount from the Docket No. 10894 refunds until April 1996. The $779,971 amount of the over-refund in Docket No 10894 should be carried forward into EGS's over/under-recovered fuel balance at the beginning of November 1994.

244. Based on EGS's Texas retail eligible projected fuel costs of $232,636,597 as set in Docket No. 12852, EGS's under-collection of approximately $22,894,943 in fuel costs is equivalent to 9.5 percent, which exceeds the threshold limit of 4 0 percent set forth in P U C SUBST. R. 23.23(b)(2)(A)(iii)(II).

245. EGS continues in a state of material under-collection of its fuel costs and is in the process of surcharging its net fuel cost under-recovery as calculated in the schedules attached to this Order, including interest, during the billing months of May and June 1997

246. Deleted.

247. Consistent with the findings in this Order, it is appropriate for EGS to refund to its Texas retail non-fixed fuel factor customers the amounts contained in the schedules attached to this Order, with interest, during the first practical billing cycle subsequent to this Order

248. Except as indicated otherwise above, during the reconciliation period EGS generated electricity efficiently and maintained effective cost controls, and for all nonaffiliated fuel and fuel-related contracts, its contract negotiations produced the lowest reasonable cost of fuel to ratepayers.

B. Conclusions of Law

1. Entergy-Gulf States (EGS) is a public utility as defined in the Public Utility Regulatory Act of 1995, Tex. Rev. Civ. Stat. Ann. art 1446c-o (Vernon Supp 1997) [PURA 95] §2.0011(1).

2. The Public Utility Commission of Texas (Commission) has jurisdiction over this proceeding under PURA95 §§1.101(a), 2.001, 2 208, and 2 212(g) The jurisdiction of the Commission extends to all Texas retail customers of EGS, including those customers that pay the fixed fuel factor and those that are classified as non-fixed fuel factor customers

3. The State Office Of Administrative Hearings (SOAH) has jurisdiction over all matters relating to the conduct of a hearing, including the preparation of a proposal for decision with findings of fact and conclusions of law in this proceeding pursuant to PURA 95 §1 101(e) and TEX. GOV'T. CODE ANN. Ch. 2003.047.

4. EGS provided published and direct notice of its application in this proceeding as required by P.U.C. SUBST. R. 23.23(b)(4).

5. P.U.C. SUBST. R. 23.23(b) (eff. May 1, 1993) applies to this proceeding because EGS's fixed fuel factors in effect during the first two months of the reconciliation period (January and February 1994) were set in Docket No. 10894, decided on August 19, 1993, after the May 1, 1993 effective date. EGS's fixed fuel factors in effect for the remainder of the reconciliation period were set in Docket No. 12712, decided on April 28, 1994

6. A utility's expense is not an allowable reconcilable fuel cost to the extent it resulted from the utility's imprudence, or was not reasonable and necessary to provide reliable electric service, as set forth in P.U.C. SUBST. R. 23.23(b)(3)(B)(i)(I).

7. The scope of a fuel reconciliation proceeding includes any issue related to determining the reasonableness of the utility's fuel expenses during the reconciliation period and whether the utility has over- or under-recovered its reasonable fuel expenses. P.U.C. SUBST R 23.23(b)(3)(B)(i).

8. Prudence is the exercise of that judgment and the choosing of one of that select range of options which a reasonable utility manager would exercise or choose in the same or similar circumstances given the information or alternatives available at the point in time such judgment is exercised or option is chosen. There may be more than one prudent option within the range available to a utility in any given context. Any choice within the select range of reasonable options is prudent, and the Commission should not substitute is judgment for that of the utility The reasonableness of an action or decision must be judged in light of the circumstances, information, and available options existing at the time, without benefit of hindsight. *Inquiry of the Public Utility Commission of Texas into the Prudence and Efficiency of the Planning and Management of the Construction of the South Texas Nuclear Project,* Docket No. 6668, 16 P.U.C. BULL. 183, 483 (June 20, 1990); and *Petition of Southwestern Public Service Company for a Fuel Reconciliation,* Docket No. 14174, __ P.U.C. BULL. __ (Jan. 5, 1996) (not yet published).

9. An isolated error or failure to identify or correct an isolated problem can constitute imprudence; however, whether it does or not depends upon whether the utility's conduct accords with the prudence standard as stated above. *Application of Gulf States Utilities Company to Reconcile Fuel Costs, Establish New Fixed Fuel Factors, and Recover its Under-Recovered Fuel Expense,* Docket No. 10894, 19 P.U.C. BULL. 1401, 1419 (April 28, 1994).

9A. Utility management is responsible for the work-related actions and decisions of its employees. Utility management is responsible for establishing, monitoring and enforcing appropriate operations and procedures and for ensuring that its employees perform up to those standards. Inadequate, substandard, or otherwise inappropriate work methods or products reflect the cumulative actions and decisions of utility management

10. If its eligible fuel expenses for the reconciliation period included an item or class of items supplied by an affiliate of the utility, the utility has the burden of showing that the prices charged by the supplying affiliate to the utility were reasonable and necessary and no higher than the prices charged by the supplying affiliate to its other affiliates or divisions or to unaffiliated persons or corporations for the same item or class of items P U C SUBST R 23.23(b)(3)(B)(i)(II).

11. The doctrine of *res judicata*, or claim preclusion, bars litigation of all issues connected with a cause of action or defense, which, with the use of diligence, might have been tried in the prior suit. The doctrine of collateral estoppel, or issue preclusion, bars the re-litigation of any ultimate issue of fact actually litigated and essential to the judgment in a prior suit, regardless of whether the second suit is based upon the same cause of action *Bonniwell v. Beech Aircraft Corp.*, 663 S.W.2d 816, 818 (Tex. 1984). The doctrine of collateral estoppel requires that the facts sought to be litigated in the second action were fully and fairly litigated in the prior action *Bonniwell*, 663 S.W.2d at 818.

12. Because the stipulation and final order in Docket No 13170 specifically reserved, in a non-contested proceeding, the review of the reasonableness of certain fuel issues, *res judicata* does not preclude the consideration of those issues in this docket

13. EGS, the other Entergy Operating Companies, and System Fuels, Inc , are affiliates under PURA 95 §1.003(2).

14. EGS successfully carried its burden of proof to show that its purchased power and fuel oil transactions with its affiliates during the reconciliation period occurred at reasonable and necessary prices charged by the affiliates and were at prices that were no higher than the prices charged by the supplying affiliates to its other affiliates or divisions or to unaffiliated persons or corporations for the same item or class of items in accordance with P.U.C. SUBST. R 23.23(b)(3)(B)(i)(II) and PURA 95 §2.208(b).

15. EGS's Agrilectric purchased power transaction expenses above EGS's avoided cost during the reconciliation period were not reasonable and necessary, and therefore not in accordance with P.U.C. SUBST. R. 23.23(b)(3)(B)(i)(I).

15A. A utility has a continual obligation to reasonably pursue the renegotiation of above-market contracts on behalf of its ratepayers. Accordingly, in a fuel reconciliation proceeding, a utility has the burden of proving that its contract renegotiation efforts (or lack thereof) were reasonable in light of its particular contractual obligations and other relevant circumstances.

16. EGS's long- and short-term natural gas contracts and expenses were reasonable and necessary to provide reliable electric service to its customers during the reconciliation period, with the exception of: (a) $62,958 in spot-gas purchases at Willow Glen in March 1994, which EGS failed to show was reasonable and necessary as required by P.U.C. SUBST. R 23.23(b)(3)(B)(i)(I), and (b) $3,473,207 in short-term natural gas expenditures for which EGS failed to meet its burden of proof in demonstrating that such expenses were reasonable and necessary.

17. EGS failed to show that 12.94 days of Refueling Outage 5 (RF-5) at River Bend Nuclear Station (RBNS) were prudently planned and managed; therefore, EGS's replacement purchased power costs for that portion of RF-5 were not reasonable and necessary as required by P.U.C SUBST. R. 23.23(b)(3)(B)(i)(I). Under traditional cost-of-service rate regulation applicable to EGS, EGS ratepayers should bear the risk of costs associated with an extended forced outage that is not caused in whole or in part by imprudent management. However, implementation in

the future of a variation of cost-of-service-based regulation, such as performance-based regulation, may necessitate deviating from the traditional application of the prudence standard

17A. EGS failed to show that $1,519,787 of replacement power costs associated with forced outage FO-94-01 were reasonable and necessary as required by P U C SUBST R 23.23(b)(3)(B)(i)(I).

17B. EGS failed to show that $545,548 of replacement power costs associated with forced outage FO-94-02 were reasonable and necessary as required by P U C SUBST R 23.23(b)(3)(B)(i)(I).

17C. EGS failed to show that $657,386 of replacement power costs associated with forced outage FO-94-03 were reasonable and necessary as required by P U C SUBST R 23.23(b)(3)(B)(i)(I).

18. EGS did not properly and accurately account for $90,653 in coal costs for the month of September 1994 at Big Cajun II, Unit 3, during the reconciliation period and that expense is not reasonable as required by P.U.C. SUBST. R. 23 23(b)(3)(B)(i) and (ii)

19. EGS failed to accurately justify $226,447 in replacement power costs for Big Cajun II, Unit 3, with interest on a Texas retail basis, as reasonable and necessary fuel expenses incurred during the reconciliation period as required by P U C SUBST R 23 23(b)(3)(B)(i) and (ii)

20. The Commission has the discretion under P U C SUBST R 23 23(b)(1) and (b)(3)(B)(ii) to proportionately and consistently allocate fuel costs among fixed- and non-fixed-fuel-factor customers. Because, EGS did not establish that its fuel cost allocation methodology proportionately and consistently allocates fuel costs to fixed- and non-fixed fuel-factor customers based on EGS's actual incurrence of fuel costs to serve them, the Commission is well within its discretion to adopt a just and reasonable fuel cost allocation methodology based on

actual fuel cost incurrence, and is not requir
customer pays rates based on EGS's system av

21. Deleted.

22. Deleted.

23. Deleted.

24. Except as provided otherwise in the Fi
PURA 95 §§2.212(g), 2.208(b), and P.U.C. S
requested be treated as allowable reconcilable

X. Orderi

1. The petition filed by EGS on Decemb
January 1, 1994 through June 30, 1995

2. EGS shall surcharge its Texas retail
recovery allocable to such customers,
June 1997 consumption. To the ext
amounts contained in the schedules
reflected in the reconcilable fuel balan

3. EGS shall refund to its Texas reta
contained in the schedules attached
practicable billing cycle following the

4. EGS shall file, on or before August 3
the projected and actual amounts surch
pursuant to this Order.

5. All motions, applications, or other requests for relief not expressly granted in this Order are denied for want of merit.

SIGNED AT AUSTIN, TEXAS the 24th day of June, 1997.

PUBLIC UTILITY COMMISSION OF TEXAS

PAT WOOD, III, CHAIRMAN

ROBERT W. GEE, COMMISSIONER

JUDY WALSH, COMMISSIONER

ALLOCATION OF SYSTEMWIDE FUEL COST DISALLOWANCES TO TEXAS RETAIL FIXED FUEL AND NON-FIXED FUEL FACTOR CUSTOMERS - Schedule JBG-1

Line	Description	Total	Jan-94	Feb-94	Mar-94	Apr-94	May-94	Jun-94	Jul-94	Aug-94	Sep-94
1	GSU Adjusted System kWh Sales @ Plant (FR-21) [Line 3 fromTIEC Reply adjusted for rounding]	46,213,139,392	2,394,591,334	2,446,707,761	2,281,852,590	2,401,960,467	2,404,810,746	2,825,900,534	3,000,389,355	2,897,328,175	3,013,215,820
2	KWh Sales @ Meter (FR-21A)										
3	SSTS	402,982,658	4,422,944	19,624,576	13 143,096	13,216,990	13,057,866	19 863,371	25,987,032	26,625,692	35,568,983
4	SUS	1,371,159,547	77,606,736	86,008,442	80,817,667	90,329,206	84,769,951	89,543,808	90,263,178	88,445,999	86,127,474
5	SMQ	318,616,748	7,837,738	26,551,843	28,686,342	39,560,913	15,627,390	26,102,327	19,708,603	12,949,915	8,352,455
6	EAPS	101,358,617	2,896,731	2,694,046	4,382,933	4,466,486	9,474,801	10,078,707	11,163,817	5,122,839	3,344,574
7	MSS	415,982	0	0	0	26,173	0	0	0	0	0
8	Loss Factor (JM-1)										
9	69/138 kV	1 020553	1 020553	1 020553	1 020553	1 020553	1 020553	1 020553	1 020553	1 020553	1 020553
10	KWh Sales @ Plant for Tariff (Meter*Loss Factor)										
11	SSTS	411,265,161	4,513,849	20,027,920	13,413,226	13,488,639	13,326,244	20,271,623	26,521,143	27,172,930	36,300,032
12	SUS	1,399,340,989	79,201,787	87,776,174	82,478,713	92,185,742	86,512,228	91,384,202	92,118,357	90,263,830	87,897,652
13	SMQ	325,165,278	7,998,827	27,097,563	29,275,932	40,374,008	15,948,580	26,638,808	20,113,674	13,216,075	8,524,123
14	EAPS	103,441,841	2,956,268	2,749,417	4,473,015	4,558,286	9,669,537	10,285,855	11,393,267	5,228,129	3,413,315
15	MSS	424,532	0	0	0	26,711	0	0	0	0	0
16	Allocation Factor (Tariff/Adjusted System)										
17	SSTS	0 890%	0 189%	0 819%	0.588%	0.562%	0 554%	0.717%	0 884%	0 938%	1 205%
18	SUS	2.967%	3 241%	3.515%	3 542%	3.761%	3 525%	3.169%	3 008%	3 053%	2 858%
19	SMQ	0 689%	0 327%	1 085%	1.257%	1.647%	0 650%	0 924%	0 657%	0 447%	0 277%
20	EAPS	0.219%	0 121%	0 110%	0 192%	0 186%	0.394%	0 357%	0 372%	0 177%	0 111%
21	MSS	0 001%	0.000%	0 000%	0 000%	0 001%	0 000%	0 000%	0 000%	0 000%	0 000%
22	Disallowances (WP to FR-21)										
23	Total	$11,088,937	$704,095	$924,057	$115,343	$85,104	$92,401	$1,689,555	$1,449,262	($243,907)	$377,421
24	Gas Contracts	$3,473,207	$683,038	$840,038	$0	$91,869	$0	$716,730	$97,632	$32,506	$71,279
25	All Other	$7,615,730	$21,057	$84,019	$115,343	($6,765)	$92,401	$972,825	$1,351,630	($276,413)	$306,142
26	Disallowance Allocated										
27	SSTS (Line 23*Allocation Factor)	$106,339	$1,327	$7,564	$678	$478	$512	$12,120	$12,810	($2,288)	$4,547
28	SUS (Line 24*Allocation Factor)	$109,227	$22,137	$29,530	$0	$3,455	$0	$22,711	$2,937	$992	$2,037
29	SMQ (Line 24*Allocation Factor)	$26,485	$2,236	$9,116	$0	$1,513	$0	$6,620	$641	$145	$198
30	EAPS (Line 24*Allocation Factor)	$6,756	$826	$925	$0	$171	$0	$2,556	$363	$57	$79
31	MSS (Line 24*Allocation Factor)	$4	$0	$0	$0	$1	$0	$0	$0	$0	$0

ALLOCATION OF SYSTEMWIDE FUEL COST DISALLOWANCES TO TEXAS RETAIL FIXED FUEL AND NON-FIXED FUEL FACTOR CUSTOMERS - Schedule JBG-1

Line	Description	Oct-94	Nov-94	Dec-94	Jan-95	Feb-95	Mar-95	Apr-95	May-95	Jun-95
1	GSU Adjusted System kWh Sales @ Plant (FR-21) [Line 3 from TIEC Reply adjusted for rounding]	2,723,469,648	2,423,371,375	2,548,541,197	2,464,212,161	2,444,556,507	2,299,256,924	2,282,068,373	2,429,747,033	2,931,161,392
2	KWh Sales @ Meter (FR-21A)									
3	SSTS	37,275,995	35,432,195	21,968,263	10,593,372	40,320,468	19,402,621	16,726,522	26,601,950	23,150,722
4	SUS	84,999,707	84,250,165	89,333,925	57,387,962	57,057,832	53,934,787	60,286,555	48,143,022	61,853,131
5	SMQ	33,502,745	19,684,681	5,076,904	13,286,334	13,647,903	5,922,926	7,485,699	14,833,235	19,798,795
6	EAPS	6,812,960	6,969,240	6,925,962	2,897,315	3,856,806	2,948,911	2,536,267	3,749,366	11,036,856
7	MSS	0	0	0	198,368	0	0	0	127,810	63,631
8	Loss Factor (JM-1)									
9	69/138 kV	1.020553	1.020553	1.020553	1.020553	1.020553	1.020553	1.020553	1.020553	1.020553
10	KWh Sales @ Plant for Tariff (Meter*Loss Factor)									
11	SSTS	38,042,129	36,160,433	22,419,777	10,811,098	41,149,175	19,801,403	17,070,302	27,148,700	23,626,539
12	SUS	86,746,706	85,981,759	91,170,005	58,567,457	58,230,542	55,043,309	61,525,625	49,132,506	63,124,398
13	SMQ	34,191,327	20,089,260	5,181,250	13,559,408	13,928,408	6,044,660	7,639,553	15,138,102	20,205,720
14	EAPS	6,952,987	7,112,479	7,068,311	2,956,864	3,936,075	3,009,520	2,588,395	3,826,427	11,263,697
15	MSS	0	0	0	202,445	0	0	0	130,437	64,939
16	Allocation Factor (Tariff/Adjusted System)									
17	SSTS	1.397%	1.492%	0.880%	0.439%	1.683%	0.861%	0.748%	1.117%	0.806%
18	SUS	3.121%	3.477%	3.505%	2.329%	2.334%	2.346%	2.642%	1.981%	2.110%
19	SMQ	1.230%	0.812%	0.199%	0.539%	0.558%	0.258%	0.328%	0.610%	0.675%
20	EAPS	0.250%	0.288%	0.272%	0.118%	0.158%	0.128%	0.111%	0.154%	0.377%
21	MSS	0.000%	0.000%	0.000%	0.008%	0.000%	0.000%	0.000%	0.005%	0.002%
22	Disallowances (WP to FR-21)									
23	Total	$2,185,625	$1,150,429	$883,636	$794,172	$685	($524,569)	$245,196	$949,406	$211,026
24	Gas Contracts	$190,023	$86,173	$69,178	$38,789	$372,289	$107,047	$68,179	$5,111	$3,326
25	All Other	$1,995,602	$1,064,256	$814,458	$755,383	($371,604)	($631,616)	$177,017	$944,295	$207,700
26	Disallowance Allocated									
27	SSTS (Line 23*Allocation Factor)	$30,529	$17,166	$7,773	$3,484	$12	($4,518)	$1,834	$10,608	$1,701
28	SUS (Line 24*Allocation Factor)	$5,931	$2,996	$2,425	$903	$8,690	$2,511	$1,801	$101	$70
29	SMQ (Line 24*Allocation Factor)	$2,338	$700	$138	$209	$2,078	$276	$224	$31	$22
30	EAPS (Line 24*Allocation Factor)	$475	$248	$188	$46	$587	$137	$76	$8	$13
31	MSS (Line 24*Allocation Factor)	$0	$0	$0	$3	$0	$0	$0	$0	$0