c. ALJ's Recommendation.

i. Was the extended forced outage 94-03 at River Bend due, in whole or in part, to imprudent management by GSU/Entergy? (Preliminary Order Issue No. 7)

The ALJ finds that extended outage number 94-03 at River Bend, or forced outage number FO-94-01, was not due in whole or in part to imprudent management by GSU because the September 8, 1994 spurious reactor vessel high-water level signal and reactor shutdown was not caused by either the failure to install damping or the incorrect damping of the transmitters. Therefore, the outage was not due to imprudent management by GSU or Entergy. GSU's and Commission Staff's witnesses both concluded, by means of a generally accepted mathematical proof,[26] that a noise signal of the amplitude experienced in the RBNS reactor vessel on September 8, 1994, would have caused a trip or reactor scram even if the maximum damping possible had been installed on the Rosemount Model 1153 transmitters. Ex. EGS-13 at 16; and Ex. GC-11A at 5. The ALJ concludes that there should be no disallowance for the replacement power costs attributable to this outage. The ALJ finds Cities' analysis faulty because it failed to adequately account for the cause of the outage.

The ALJ finds that the irrefutable mathematical proof generally accepted in nuclear engineering circles and presented in Staff witness Dishong's testimony demonstrates that even with maximum damping installed, a noise signal of the amplitude experienced at RBNS on September 8, 1994 would still have resulted in a reactor shutdown. Ex. GC-11A at 5. As Staff witness Mr. Glenn Dishong put it: "..the cause of this forced outage was not preventable."

26. The general formula relating output signals in the Rosemount 1153 transmitters to input signals is an exponential formula, as follows: Delta P(output)= Delta P(input) x (1-e to the Delta tau)/t). The variable Delta P(output) is defined as a change in the pressure signal output from the transmitter, read in inches of vessel water level. The variable Delta P(input) is a change in the pressure signal input to the transmitter read in inches of vessel water level. The term "e" is the exponential function. Delta tau is t1-t0, or the time duration considered, in seconds, where t0 is the selected beginning time and t1 is the selected ending time. In this case, t0 is the time of the beginning of the noise event, and t1 is the time of the ending of the noise surge represented by the peak of the noise spike. Measurements indicated that the Delta tau for the noise spike was 0.4 seconds. Finally, the term "t" is the time constant for the transmitter as set, in seconds. This time constant for the transmitter changes as the position of the damping potentiometer on the transmitter is changed. Ex. GC-11A, Attachment MBS-10 at 3.

Ex. GC-11A at 5. The ALJ rejects Cities' analysis because it did not give proper weight to the cause of the outage. Therefore, the ALJ finds that extended forced outage 94-03 was not due in whole or in part to imprudent management on the part of GSU or Entergy. Accordingly, the ALJ recommends that the Commission find that the outage was not caused in whole or in part by imprudent management on GSU's part and order no disallowance for the replacement power costs attributable to outage number 94-03, or FO-94-01 at RBNS.

ii. Assuming that the extended forced outage 94-03 at River Bend was *not* due to imprudent management and that fuel costs for GSU increased as a result of the outage, should GSU be required to absorb some or all of the increased fuel costs, or should this risk be borne entirely by GSU's ratepayers? (Preliminary Order Issue No. 8)

The ALJ finds that because extended forced outage number 94-03 at RBNS was not due to imprudent management, although the fuel costs for GSU increased as a result of the outage, GSU should not be required to absorb any of the increased fuel costs. This issue was addressed by GSU witness Mr. Bruce Louiselle and by Commission Staff witness Mr. Jeff Goodman, both of whom concurred that if outage 94-03 was not due to imprudent management on GSU's part, GSU should not be required to absorb any of the increased fuel costs.

The ALJ finds that under cost-of-service rate regulation, currently applicable to GSU, GSU's ratepayers should bear the risk of costs not imprudently incurred which are associated with the outage (FO-94-01). Ex. GC-9 at 25-26; and Ex. EGS-20 at 6. If the Commission were to require GSU to absorb some or all of the replacement power costs incurred as a result of outage 94-03 at RBNS, the Commission would be imposing an unwarranted penalty on GSU under the principles of cost-of-service rate regulation. No other party offered evidence to the contrary on this issue. Therefore, the ALJ recommends that the Commission find that GSU should not be required to absorb any of the increased fuel costs associated with extended [forced] outage 94-03, or FO-94-01, because it was not caused by imprudent management on GSU's part.

3. Forced Outage 94-02 (FO-94-02); Outage No. 94-04: Recirculation Pump Seals.

On October 8, 1994, outage number 94-04, (forced outage FO-94-02), occurred at RBNS due to the failure of a recirculation pump seal, requiring a reactor shutdown for repairs to be made. This outage lasted 5.8 days, ending on November 3, 1994. GSU had replaced the failed recirculation pump seals prior to this outage with a new-type seal during the earlier refueling outage, RF-5. Before RF-5, the recirculation pump seals had been replaced several times. The new design was an attempt to correct the performance problems encountered with the previous design. Ex. GC-11 at 16-17.

a. GSU's Replacement of the Pump Seals with Tungsten-Carbide Material.

The new recirculation pump-seal design failed due to accelerated wear caused by particles in the reactor cooling water, even though GSU had previously carried out a thorough plan to evaluate potential seal materials. In addition to getting a recommendation from the seal manufacturer (BW/IP) and the plant's designer (GE), GSU contracted with a consulting firm (MPS Assoc.) to evaluate the two choices for the seal material. MPS recommended using the old, industry-proven tungsten carbide material for three reasons: (1) the new material, silicon-carbide, with improved performance in a high particulate environment offered little benefit, given River Bend's high purity seal water supply; (2) the industry operating experience with the new silicon carbide seal material was limited to only one BWR nuclear plant in the world, and that was limited to only four months; and (3) the manufacturer also supported the use of the tungsten carbide material in its seals. Ex. GC-11 at 17-18. GSU therefore chose the tungsten carbide material.

b. Cities' Recommended Disallowance.

Cities' witness Mr. Richard Hubbard testified that in his opinion, outage number 94-04 was avoidable. In his view, the water quality particulate count data indicated that satisfactory long-term seal performance would not be achievable with the tungsten-carbide seal design that was installed during RF-5. Mr. Hubbard viewed the need to replace the recirculation pump seals twice in six months as another example of a long standing unresolved materials problem at RBNS. Mr. Hubbard concluded that the combination of the unknown source for the "crud-burst"[27] phenomenon, the water quality particulate data, the susceptibility of the seals to particulates, and the history of frequent seal replacement, all considered together, indicate that the management of the design of the recirculation pump seals at RBNS was not reasonable. Ex. Cities-48 at 79-80. Mr. Wheeler therefore determined that the entire 5.8 day or 140.1 hour duration of outage number 94-04 was unreasonable and was management's responsibility. Ex. Cities-49. Mr. Hubbard quantified the avoidable nuclear fuel costs attributable to the outage at a total of $545,548. Ex. Cities-48 at 92-93.

c. ALJ's Recommendation.

The issue is whether GSU's management was unreasonable or caused outage number 94-04 at RBNS by its decision to replace the recirculation pump seal material during RF-5 with the same tungsten-carbide material as recommended by the consultants and manufacturer, instead of the untested silicon-carbide material if there was no reason to suspect poor water quality in the recirculation system at RBNS.

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27. A "crud burst" is a phenomenon that occurs due to particulate accumulation on the inside surfaces of water pipes during normal operation. Sometimes, the operation of a valve or a change in flow or water chemistry or some other event causing a jarring of the pipes may cause the particulates to be released from the inside wall of the pipe. This sudden release of particulates is known as a crud burst. The seal water quality testing that GSU and the seal manufacturer BW/IP performed at RBNS covered all modes of plant operation that could reasonably be simulated including shutdown and startup operations. It is during these times that a crud burst will most likely occur because more system changes occur during shutdown and startup operations. The seal water quality test results did not reflect a particulate problem due to the crud burst phenomenon at RBNS. Ex. EGS-13 at 30.

The ALJ finds that GSU was not imprudent in choosing the tungsten-carbide rather than the silicon-carbide recirculation pump material even after the history of repeated failures because the new silicon-carbide material was not a sufficiently industry-proven material for the application. *See* Ex. GC-11 at 17. The industry operating experience with the silicon-carbide material was limited to only one other BWR nuclear reactor in the world, and that experience was limited to only four months. The ALJ finds that GSU reasonably investigated the use of both materials and prudently chose the industry-proven tungsten-carbide material for the seals' replacement during RF-5 and GSU prudently planned and executed outage number 94-04 from the start. Ex. GC-11 at 17-18.

Furthermore, there was no reason to suspect poor water quality of the seal water because GSU and the seal manufacturer had tested the water quality prior to replacing the seals under various plant operating conditions, and the test results showed a high purity seal water supply. Ex. GC-11 at 17; and Ex. EGS-40; and Ex. EGS-13 at 30 ("The readings indicated that particulate levels were not high enough to be a concern at River Bend"). The seal water quality tests performed by GSU and BW/IP did not reveal a particulate problem due to the "crud burst" phenomenon at RBNS. Ex. EGS-13 at 30.

The Cities' analysis seemed to focus on recurring problems at RBNS, rather than the reasonableness of GSU's management action to correct such problems under the existing circumstances and given the information available to make those decisions at the time. Therefore, the ALJ rejects Cities' recommended disallowance of the entire 5.8 day outage and recommends that the Commission find that GSU's outage number 94-04 at RBNS was not due to unreasonable or imprudent management decisions.

4. Forced Outage 94-03 (FO-94-03); Outage No. 94-05: Human Error.

Outage number 94-05, or forced outage number FO-94-03 at RBNS, occurred on December 4, 1994, and lasted approximately 7.4 days, ending on December 12, 1994. Ex. Cities-48 at 80-81; and Ex. GC-11 at 18. This outage was caused by a technician who made an error which caused a reactor trip or scram during the monthly testing of the Main Steam Isolation Valves (MSIVs) at RBNS.

a. MSIV Isolation Testing--Operator Error Due to Miscommunication.

During the monthly testing of the MSIVs at RBNS, a half isolation of the controls for the MSIVs was initiated. A half isolation involves completing one-half of the logic for an automatic closure of the MSIVs. The test is designed such that only a single, one-half isolation is encountered at a time. Two concurrent one-half isolations will cause closure of the MSIVs and a plant scram. During the 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. Upon hearing this communication, the technician signed-off on the reset procedure step, and the test proceeded to the next section. The next section involved inserting the second half isolation in the logic. Because the first 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 scram and the forced outage. Ex. EGS-13 at 32.

b. Cities' Recommended Disallowance--Management Procedures Ineffective.

Cities' witness Mr. Richard Hubbard concluded that the technician's error was within GSU's control and that GSU had been forewarned. He concluded that GSU's attention was supposed to be focused on reducing human errors that occurred during the maintenance at RBNS, and that it was not reasonable for this type of error to have occurred. He therefore recommended that the associated time for the outage be disallowed. Ex. Cities-48 at 83. Mr. Hubbard found that there was insufficient information to draw any conclusions regarding the prudence of the vacuum breaker arm repairs, but nevertheless recommended disallowance of time for this repair as well. In summary, Mr. Hubbard found that GSU was imprudent in the maintenance technician's error causing the outage, as well as the vacuum breaker arm/drywell leak and CRD piping repair, and he recommended that the entire outage be disallowed. Ex. Cities-48 at 86.

GSU witness Mr. Michael B. Sellman testified on rebuttal that GSU had never before had a problem with human performance in completion of the MSIV test and that the procedure had previously been reviewed for human performance. Therefore, it was reasonable for GSU management to believe that the test procedures were not a source of concern. Further, this particular testing procedure is not complicated and the technician involved had never before been responsible for a human performance error during the conduct of a procedure resulting in any significant consequences. The technician had received training on communications call-back procedures, yet he still made the error. Ex. EGS-67 at 63-65.

Commission Staff witness Mr. Glenn Dishong testified that the GSU technician's error was caused by a miscommunication during the MSIV testing. Mr. Dishong testified that although GSU management had a clear policy (ADM-022) regarding the proper method for communications at RBNS, it was unlikely that any GSU management intervention would have prevented the technician's error. This communication policy was in effect at the time of the MSIV testing in question and required the call-back of communications from technician to operator, creating a "closed loop" of communication. Ex. EGS-67 at 64. According to Mr. Dishong, personnel errors or equipment malfunctions causing an automatic reactor shutdown to occur are expected to happen at nuclear power plants from time to time.

Mr. Dishong further testified that he did not agree with Mr. Hubbard's testimony implying that the technician's miscommunication was not an isolated occurrence. Mr. Dishong stated that it was no surprise that the NRC had identified the miscommunication as a contributor or cause of the outage, but that the NRC's finding did not mean that miscommunication was a pervasive problem at RBNS. Mr. Hubbard's assertion that this type of error has been a historical problem at RBNS is inaccurate, according to Mr. Dishong. The incident was not caused by a failure to follow the procedures at RBNS, but by an isolated misunderstanding of a specific verbal communication. Mr. Dishong also testified that the incident had nothing to do with equipment malfunction. Ex. GC-11 at 19.

c. **ALJ's Recommendation.**

The ALJ agrees with Mr. Dishong and finds that GSU management could not have prevented the human error that caused outage number 94-05 at RBNS. Cities' analysis fails to give sufficient consideration or weight to the actual cause of the outage. The ALJ finds that the MSIV testing error and resulting outage was not caused by a failure to follow operating procedures in effect at RBNS, but by an isolated misunderstanding of a specific verbal communication and was therefore due to human error. The ALJ agrees with Commission Staff witness Dishong's assessment and finds that personnel errors in the form of human errors causing a reactor shutdown are expected to occur at nuclear power plants like RBNS from time to time and that GSU's management could not have prevented the occurrence.

The ALJ finds that it was unlikely that GSU management intervention beforehand could have prevented the technician's communication error, and the fact that the NRC had cited GSU for the error as a contributing cause for the outage does not indicate that technician miscommunication was a pre-existing problem at RBNS. *See* Ex. GC-11 at 18-19. Furthermore, the fact that there was a clear communication policy in effect at RBNS at the time and that the technician had received training in it lends greater credibility to the explanation of the event as attributable to isolated human error.

Therefore, the ALJ finds that outage number 94-05, (forced outage FO-94-03) at RBNS was not due to unreasonable or imprudent management by GSU, but was instead due to human error and that none of the outage duration should be disallowed. The ALJ therefore recommends that the Commission make findings consistent with the Commission Staff's assessment of the outage and that there are no disallowances appropriate for this outage.

XI. Purchased Power Expenses and Affiliate Transactions

A. Purchased Power Supplied by GSU's Affiliate Entergy Operating Companies

As a result of the operation of the ESA, GSU paid $36,936,199.02 to its affiliate Entergy operating companies (EOCs) for energy it received from the Entergy system pool during the reconciliation period. Ex. EGS-4 at 12; and Tr. Vol. III at 685-686. This amount of purchased power affiliate EOC expenses represents approximately 1,838,569 MWh of electricity purchased from affiliated EOCs during the reconciliation period at an average cost of $20.09 per MWh. Ex. EGS-4 at 12. GSU argues in its brief that its affiliate purchased power costs and the revenue allocations made to it resulted from the application of the FERC-approved ESA and Service Schedules, and therefore, the payments made to these affiliate EOCs were reasonable and necessary.

GSU witness Mr. Shelton Cunningham testified that the FERC has determined that the ESA is a just and reasonable way of equalizing and allocating the costs and revenues generated by an integrated system such as Entergy's. FERC has also determined that the charges imposed on GSU by the ESA are fair and reasonable in relation to the other EOCs.[28] Although each EOC's allocation varies based on its relative size and operating characteristics, Mr. Cunningham testified that the ESA ensures that GSU is paying proportionately no more for power than any of its affiliate EOCs that are also parties to it. Ex. EGS-5 at 13.

28. Opinion No. 234, *Middle South Energy, Inc.*, 31 F.E.R.C. (CCH) Par. 61,305 (1985); and Opinion No. 385, *Entergy Services, Inc., and Gulf States Utilities Company*, 65 F.E.R.C. (CCH) Par. 61,332 (1993).

B. Whether Fuel and Purchased Power Supplied to GSU by its Affiliates During the Reconciliation Period was in Accordance with PURA 95 §2.208(b) (Preliminary Order Issue No. 1)

1. GSU's System Agreement Payments to Affiliated Entergy Operating Companies-- Purchased Power Affiliate Transactions.

Schedule MSS-3 of the ESA determines the pricing and exchange of energy among the EOCs. According to the Entergy economic dispatch system, each EOC has first call on its own generation and makes exchange energy sales when it has energy from its own units in excess of its own demands and that is cheaper than resources available to the other EOCs. EGS-5 at 9. By approving Schedule MSS-3, the FERC has determined how the EOCs will be reimbursed for energy sold to the exchange pool and how it will purchase energy from the pool. As discussed at Section XI A, above, if an EOC such as GSU supplies energy to the pool that the particular EOC produced, it receives an Operations & Maintenance (O&M) "adder,"[29] the purpose of which is to reimburse the EOC for incremental costs associated with making the sale to the exchange pool. This O&M "adder" is not reflected in fuel costs. Tr. Vol. III at 704-706; and 638-639. 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 cost of the energy. Tr. Vol. III at 706.

The ALJ finds that the FERC has determined the terms and pricing of these affiliate transactions and how the EOCs will be charged and reimbursed for energy purchased and sold to the exchange. The FERC has determined that the ESA is reasonable as applied to all affiliate EOCs who are parties to the ESA, including GSU. Ex. EGS-5, and ESA Schedule MSS-3. Because the O&M adder is not reflected in the EOC's fuel costs and does not include a profit like the off-system sales adder addressed in the Commission Preliminary Order, the ALJ finds GSU's power purchases from the Entergy system pool during the reconciliation period of $36,936,199.02 to be reasonable and

29. More specifically, this "O&M adder," is governed by the FERC-approved ESA and schedules. The off-system sales "adder" referenced in Commission Preliminary Order Issue No. 9 is a profit margin or "adder" that GSU receives when it makes certain off-system sales for its own benefit to non-EOCs.

necessary. The ALJ further finds such purchases by GSU were made at an average price of $20.09/MWh and that such price was no higher than the prices charged by the supplying EOC or affiliate to the other EOCs or affiliates during the reconciliation period.

Cities contended that GSU failed to meet its "burden of proof to show that off-system sales revenue recovers fuel costs." Cities' In. Brief at 74. The ALJ rejects this argument for two reasons. First, the ALJ finds that GSU's burden of proof on this issue is to show that its eligible fuel expenses were reasonable and necessary and that it has properly accounted for these revenues. Subst. R. 23.23(b)(3)(B). The ALJ believes the Cities have invented a burden of proof that revenues from off-system sales must recover fuel costs, a requirement not imposed by the rule. Further, contrary to Cities' claims, the ALJ believes that the data Cities offered in support of its contention reflect only that GSU may not have received as much per MWh for off-system sales as the other EOCs.

GSU witness Mr. J.David Wright testified that the revenue differential resulted from the order of the FERC mandating that GSU could not share in the profits from off-system sales under existing pre-merger contracts. Tr. Vol. X at 2444; and Ex.EGS-5 at SGC-1, Schedule MSS-5, Section 50.03. Schedule MSS-5 provides that Entergy Gulf States be reimbursed for its cost of fuel to supply the pre-merger sales, plus an O&M adder, but that GSU not share in the net revenue balance or profit. The ALJ finds Cities' argument that GSU's ratepayers have somehow been cheated by these off-system sales is not supported by the facts. GSU shared in the profits from all off-system sales except those specifically precluded by the FERC Order. In its Opinion and Order approving the merger, the FERC found good cause for limiting GSU's participation in the profits from off-system sales contracts in existence at the time of the merger.[30] When GSU contributed energy for sales under the pre-merger contracts, it was fully reimbursed for the cost of the energy it provided. The ALJ finds that by approving Schedule MSS-5 under the ESA, the FERC has approved the allocation of off-system

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30. Opinion No. 385, *Entergy Services, Inc. and Gulf States Utilities Company*, 65 F.E.R.C. (CCH) Par. 61,332 (Dec. 15, 1993).

sales adders for O&M for the EOCs, including GSU, as reasonable and that GSU receives no off-system sales profit adder from these transactions.

The ALJ finds that although each EOC's allocation of costs and revenues may vary based on its relative size and operating characteristics, the ESA ensures that GSU is paying proportionately no more for power through the ESA than any of its affiliate EOCs who are also parties to the agreement. Ex. EGS-5 at 13. The ALJ therefore recommends that the Commission find that GSU's affiliate EOC power purchases during the reconciliation period of $36,936,199.02 are reasonable and necessary reconcilable expenses and are in accordance with PURA 95 §2.208(b).

2. Other Affiliate Transactions: The System Fuels, Inc., Transaction

Apart from GSU's purchased power transactions with affiliate EOCs and payments to NISCO at avoided cost, Commission Staff member Mr. T. Brian Almon testified that GSU had only one other affiliate transaction during the reconciliation period: in February 1994, GSU purchased 100,846 barrels of fuel oil, or approximately 605,076 MMBtu, from System Fuels, an affiliate of Entergy, at a total delivered cost of $1,189,982.80, or $11.80 per barrel. Mr. Almon testified that the $11.80 per barrel purchase price was below the market price of fuel oil at the time of the purchase according to *Platt's Oilgram*; therefore, it was lower than the average and low spot market prices on the day of the transaction. System Fuels sold the fuel oil to GSU at its inventory cost and did not make a profit. Mr. Almon concluded that the transaction with System Fuels met the requirements of PURA 95 §2.208(b). Ex. GC-12 at 11-12.

Based on the Staff's testimony, the ALJ agrees that GSU's fuel oil transaction with System Fuels during the reconciliation period meets the requirements of PURA 95 §2.208(b) because the transaction price was reasonable and necessary and was no higher than the prices charged by the supplying affiliate to its other affiliates for the same item. The ALJ finds that the System Fuels transaction price for fuel oil was reasonable and necessary because at the time of the purchase, the

$11.80 per barrel price was below the market price for fuel oil when compared to both the average and low spot market prices, according to *Platt's Oilgram*. Ex. GC-12 at 11. The ALJ finds that because GSU's System Fuels transaction fuel oil price was below market price and because GSU bought the fuel oil at System Fuels' inventory and System Fuels did not make a profit, the price for the fuel oil was no higher than the prices charged by System Fuels to its other affiliates. The ALJ therefore finds that GSU's System Fuels transaction for $1,189,982.80 was reasonable and necessary and in accordance with PURA 95 §2.208(b) and recommends that the Commission make the same finding.

C. <u>GSU's Purchased-Power Transactions with Other than GSU Affiliates or EOCs</u>.

During the reconciliation period, GSU purchased all of Agrilectric Company's net energy output at a price of $35.42/MWh pursuant to a contract rate approved by the LPSC. GSU purchased a total of $3,756,557.78 worth of purchased power from Agrilectric during the reconciliation period. Ex. GC-8 at HLH-6; and Ex. EGS-1 at Schedule FR-4.3 a-g. GSU voluntarily claimed as reconcilable purchased power expenses only that portion of the payments to the Nelson Industrial Steam Company (NISCO) which were at or below GSU's avoided cost. The PFD does not address the NISCO transactions because those expenses were included in GSU's reconciliation only in accordance with the Commission's Order in Docket No. 10894.

1. Staff's Recommendation for GSU's Purchased Power Transaction with Agrilectric.

Commission Staff witness Mr. Harold L. Hughes testified that he reviewed GSU's non-affiliate purchased-power transactions because purchases of electricity are part of the reconcilable fuel expenses for GSU. He testified that he found many of these transactions to be high. He reasoned this was attributable to prior-period adjustments or other accounting treatments that distorted the monthly unit prices. Because the GSU-Agrilectric transactions were so high, Mr. Hughes recommended GSU should be limited to avoided cost and not be permitted to recover the full cost of the transactions. In his opinion, GSU's Louisiana purchases of all of Agrilectric's $35.42/MWh net output was at a higher rate than Agrilectric would have been paid had the transactions occurred in Texas. Ex. GC-8 at 21.

Mr. Hughes concluded that if Agrilectric had been located in Texas, GSU would probably have paid them for purchased power in accordance with GSU's Commission tariff for Small Power Producers and that the total price for the purchased power under that tariff for the reconciliation period would have been approximately $1,750,800.10, or approximately $2,005,756 less than GSU actually paid Agrilectric for the power. The General Counsel therefore recommended that the Commission disallow the difference, $2,005,756, on the basis that GSU's Texas ratepayers should not pay a rate for purchased power above GSU's "avoided cost." Ex. GC-8 at 21; and HLH-6.

GSU argued that it was obliged to purchase power from Agrilectric at the rate specified in the levelized-payment contract. According to GSU, that obligation stems from P.U.C. SUBST. R. 23.66(h)(1) and (2), which sets the rates for purchases of firm power from qualifying facilities (QFs). Under that rule, a utility is required to purchase "energy and capacity" from the QF, but only if the utility needs the capacity. P.U.C. SUBST. R. 23.66(d)(1)(D). Reconcilable costs, however, do not include capacity or demand. Tr. Vol. III at 737-739; and General Counsel In. Brief at 50.

2. ALJ's Recommendation Regarding GSU's Agrilectric Transaction.

GSU did not dispute the fact that its purchased power payments to Agrilectric during the reconciliation period were above its avoided cost. The ALJ finds that GSU did not present sufficient evidence to show that it needed the capacity as required by the rule when it renegotiated the Agrilectric contract in 1994. General Counsel In. Brief at 50. The ALJ finds that GSU's payments to Agrilectric during the reconciliation period were based on a rate set by the Louisiana Commission and that there is no evidence that the Louisiana Commission has ordered GSU to buy electricity from Agrilectric.

Although the Louisiana Commission is free to set rates in Louisiana, it cannot pre-empt or set rates which the Texas Commission must find to be reasonable for customers in Texas. In the absence of any proof that GSU was obligated to pay Agrilectric for necessary capacity at the Louisiana rate, the appropriate price ceiling is that set by the Commission, GSU's avoided cost. The ALJ therefore recommends that the Commission disallow GSU's $2,005,756 payment above avoided cost for purchased-power transactions with Agrilectric during the reconciliation period.

XII. Revenues from Off-System Sales and Wheeling

A. Off-System Sales Adders

1. Is there good cause to justify an exception to the allocation of 100 percent of the revenues from off-system sales to ratepayers during the reconciliation period subsequent to the final order in Docket No. 12712? (Preliminary Order Issue No. 9)

P.U.C. SUBST. R. 23.23(b)(2)(B)(vi)(III) provides that: "[i]n addition to the expenses designated above, unless otherwise specified by the commission, eligible fuel expenses shall include: . . . . (III) revenues from off-system sales in their entirety." The parties did not dispute this requirement. GSU did not request a continuation of the 75-25 percent sharing implicitly continued after the date of the Order in Docket No. 12712 and no party provided evidence that there should be a good cause exception to the 100 percent allocation required by the rule.

2. Commission Preliminary Order Requires Allocation of Off-System Sales Adders as of April 28, 1994.

The parties disputed the date on which the 100 percent allocation should occur. GSU's position was that the 100 percent allocation of off-system sales "adders" as an offset to reconcilable fuel costs should take place beginning on April 28, 1994, as stated in the Preliminary Order. Commission Staff witness Mr. Jeff Goodman recommended that the beginning of the correct time period for the 100 percent off-system sales adder allocation to begin is March 1994, because the fuel factors adopted in Docket No. 12712 became effective in March 1994 on an interim basis, even though the date of the final order in that docket was April 28, 1994. Cities and General Counsel argued that if the interpretation of the allocation set forth in the Commission's Preliminary Order were followed literally, a month's worth of off-system sales adders would legally be 'missed' in this reconciliation. The Commission directed in its Preliminary Order that the parties were not to re-litigate the whether the 100 percent allocation of off-system sales adders to reconcilable fuel expenses should be made. Therefore, the issue centers around the correct date to begin the 100 percent allocation.

Despite the Commission's explicit language in the Preliminary Order in this docket that the sharing should end April 28, 1994, the date of the Final Order in Docket No. 12712, General Counsel and Cities contend that it should end when the interim fixed fuel factors were implemented in that docket, or March 1994. The ALJ finds that the Commission's decision about when the previously-ordered sharing of the revenues from off-system sales adders should cease was not governed by the date the interim fixed fuel factor was implemented. The critical factor was the absence in the Final Order in Docket No. 12712 of any language explicitly continuing the 75-25 percent sharing mechanism originally approved in Docket No. 10894. After noting its finding in Docket No. 10894 that a "split in margins" was reasonable, the Commission pointed out that, "[i]n contrast, in Docket No. 12712, the Commission did not specify any allocation of margins." From this absence, the Commission reasoned that no vested interest in a share of the revenues could have been conferred on GSU. Preliminary Order at 7, (February 23, 1996).

The ALJ finds that the interim fixed fuel factor was implemented by agreement among all parties to Docket No. 12712, but that the Commission did not consider and approve that factor until the date the Final Order was signed: April 28, 1994. The ALJ finds that the Commission's Preliminary Order should be interpreted consistent with the specific language it contains. Therefore, Cities' and General Counsel's proposed use of the March 1994 beginning date for ending the 75-25 percent sharing mechanism should be rejected.

The ALJ further finds that because GSU presented no evidence on the issue, there is no good cause to justify an exception to the Commission's required 100 percent allocation of GSU's off-system sales "adders" as reconcilable as required by the rule. Therefore, the ALJ recommends that the Commission find that GSU's off-system sales adders should be allocated 100 percent to reconcilable fuel costs beginning on April 28, 1994, as stated in the Commission's Preliminary Order, and that there is no good cause to justify an exception to the allocation required by the rule.

B. Transmission "Wheeling" Revenues

During the discovery phase of GSU's last application to revise its fixed-fuel factors, the parties learned for the first time that GSU had received transmission wheeling[31] revenues since the beginning of the reconciliation period.[32] Initially, GSU had not reported any wheeling revenues in this docket. For example, GSU witness Mr. J. David Wright's testimony mentioned the costs associated with off-system sales as the only credit against reconcilable fuel costs. Ex. EGS-16 at 3.

It was not until August 19, 1996, after GSU filed its motion for leave to file supplemental direct testimony of Mr. Rodney Gilbreath, that GSU produced an explanation of the omission of wheeling revenues. Actually, GSU's filing of the supplemental direct testimony of Mr. Gilbreath and motion for leave to file supplemental testimony could be considered GSU's first request for a good cause exception to the fuel rule's requirement that wheeling revenues be reported.[33] GSU witness

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31. "Wheeling" is the process whereby a utility transmits electric power over its transmission system for use by others. The revenues received from this service are known as transmission or wheeling revenues. Ex. Cities-83 at 10. As used in this PFD, the ALJ includes all of GSU's transmission-related revenues and its transmission equalization expenses booked to FERC Account 565 in the wheeling revenues category.

32. *Application of Gulf States Utilities Company to Revise Its Fixed Fuel Factors*, Docket No. 15489, __ P.U.C. BULL. __ (Aug. 12, 1996) (Final Order) (not yet reported).

33. The fuel rule provides specifically that: "In addition to the expenses designated above, unless otherwise specified by the Commission, eligible fuel expenses shall include...(II) revenues from wheeling transactions." P.U.C. SUBST. R. 23.23(b)(2)(B)(vi).

Gilbreath, through his supplemental direct testimony, explained that the transmission allocation methodology proposed by GSU was not raised as a contested issue by any party in GSU's last base rate case, Docket No. 12852, and was adopted by the Commission in its final order.

In summary, GSU's position is that because GSU's transmission wheeling revenues and expenses (or transmission equalization charges) were accorded base rate treatment in Docket No. 12852, they should not be included in this fuel proceeding. GSU's total transmission revenues received under transmission service contracts approved by the FERC between GSU and wholesale transmission customers ("Company Service")[34] amounted to $42,007,597 for the reconciliation period. Ex. EGS-17 at 2 and JDW-3. GSU's total transmission revenues associated with FERC-regulated Entergy System transmission transactions under Entergy's open access transmission tariff ("Access Service")[35] amounted to $1,501,687. Ex. EGS-17 at 2 and JDW-2. And, GSU had total transmission equalization expenses charged to FERC Account 565, which the Company incurs under Schedule MSS-2 of the ESA, of $16,565,619 during the reconciliation period. Ex. EGS-17 at 2 and JDW-1.

1. Staff's Recommendation and Substantive Rule 23.23(b) Standard for Wheeling Revenues in a Fuel Reconciliation Proceeding.

General Counsel recommended through Commission Staff witness Mr. James E. Neeley that transmission or wheeling revenues and expenses not be included in reconcilable fuel expenses in this proceeding. Ex. GC-10 at 3; and General Counsel In. Brief at 9. Mr. Neeley testified that GSU had decided to set up a separate account for its wholesale wheeling transactions and that the account contains the cost-of-service for those transactions. According to Mr. Neeley, the FERC determines

34. These are transmission revenues which GSU receives pursuant to contracts GSU entered into before the merger with Entergy. These "company service" revenues are not part of the Intra system Bill or ISB, and are therefore not allocated to any of the other EOCs. Ex. Cities-83 at 10.

35. These are transmission or wheeling revenues which GSU receives through the Entergy system and they are allocated to each of the EOCs, including GSU, on a monthly basis by operation of the ISB. Ex. Cities-83 at 12.

the cost-of-service through a hearing process. During its last base rate case, GSU proposed an inter-jurisdictional allocation of the costs associated with the wholesale wheeling transactions recorded in a separate account. The Commission approved that allocation in Docket No. 12852. Ex. GC-10 at 2.

Mr. Neeley testified that Schedule JEN-3, a schedule taken from the Commission's Final Order in Docket No. 12852, and other schedules, demonstrate that the costs of the facilities used in GSU's wholesale wheeling transactions are not allocated to Texas ratepayers. Consequently, Mr. Neeley concluded that Texas ratepayers should not benefit from the revenues received by GSU from wheeling transactions. Mr. Neeley recommended that the Commission "specify otherwise" under the fuel rule that wheeling revenues should be treated in GSU's base rates rather than as an offset to fuel expense. Ex. GC-10 at 3.

2. Cities' Argument: Wheeling Revenues Included in GSU's Fuel Reconciliation.

Cities' witness Mr. Ralph M. Griffin testified that the Commission should require GSU to include all of its wheeling revenues, less transmission equalization payments, received during the reconciliation period to offset reconcilable fuel costs. Mr. Griffin testified that because the electric utility industry is in a transition from regulation to competition, where wheeling is likely to increase tremendously in the next few years, wheeling revenues should not be treated as a base rate component only. In Mr. Griffin's opinion, if wheeling revenues were treated as a base rate component only, current levels of wheeling revenues would be locked into base rates and that GSU would realize revenues outside any regulatory control as wheeling activities increased. Ex. Cities-83 at 10-13.

The following table summarizes Mr. Griffin's calculation of wheeling revenues, which Cities contend should be reflected in this proceeding:

Description	Amount
GSU ("Company") Wheeling Revenues	$42,007,595
Transmission Service ("Access") Revenues	$ 1,507,574
Total Wheeling Revenues	$43,515,169
Less Transmission Equalization Charges	($16,503,936)
Total Wheeling Revenues-- (on a total-company basis before allocation on a Texas jurisdictional basis)	**$27,011,233**

Ex. Cities-83 at 13.

Cities' recommended calculated total wheeling revenue disallowance after allocation to GSU's Texas jurisdiction, totals approximately $11,000,000. Cities argue that GSU failed to meet its burden of proof on this issue and that the Commission's fuel rule should be followed. Cities' Reply Brief at 35-36. NSS adopted the Cities' recommendation on wheeling revenues in its closing brief. NSS Brief at 13.

GSU witness Mr. Rodney Gilbreath testified on rebuttal that Mr. Griffin's recommendation does not reflect the proper ratemaking treatment of wheeling revenues and expenses and is inconsistent with the Commission's historical treatment of wheeling revenues in GSU's last fuel and base rate cases. He testified that it is incontrovertible that transmission costs were allocated to GSU's wholesale transmission customers on a pro rata basis in GSU's last base rate case, Docket No. 12852. Therefore, he reasoned that crediting wheeling revenues in this reconciliation would give the same benefit to Texas retail customers twice, resulting in a regulatory "double-dip." Ex. EGS-68 at 3.

3. ALJ's Recommendation Regarding Wheeling Revenues.

Because transmission or wheeling costs are not allocated to Texas retail ratepayers but to a separate rate class created as a result of the Commission's Order in Docket No. 12852, GSU's last base rate case, GSU's Texas ratepayers should not benefit from the inclusion of wheeling revenues. The Commission specified an alternative treatment of GSU's wheeling revenues by adoption of the allocation of such transmission costs to a separate class in Docket No. 12852. Ex. GC-10 at 2-3. To now offset GSU's reconcilable fuel costs by including net wheeling revenues in this proceeding would result in a regulatory double-dip and inconsistent regulatory treatment. The ALJ finds that because transmission or wheeling costs were specifically allocated to a different rate class in Docket No. 12852 other than the Texas retail ratepayers' class, the Commission should accord consistent regulatory treatment of GSU's wheeling revenues and should exclude such revenues from GSU's reconcilable fuel costs for the reconciliation period.

C. Revenues from Sales of Sulfur Dioxide Emissions (SO2) Allowances

The OPC was the only party to address the treatment of GSU's revenues from sales of sulfur-dioxide (SO2) emissions[36] allowances. OPC witness Ms. Eileen Pitchford testified that SO2 emissions allowances were established by the United States Clean Air Act Amendments of 1990 (CAAA) to provide a system for controlling SO2 emissions into the atmosphere. Beginning in the year 2000, GSU must surrender one allowance for each ton of SO2 emissions released. Apparently, some generating units of other utilities were required to surrender emissions allowances beginning in 1995, but GSU and a number of other utilities will not be affected until the year 2000. The U.S. Environmental Protection Agency (EPA) allocates allowances to utilities for their generating units based on their 1985-1987 fuel usage and on statutory emissions limitations. Ex. OPC-21 at 20.

Emissions allowances may be bought, sold, or saved for future use, and the EPA has envisioned the emergence of an active allowance market where brokers, environmental groups, and

36. The element sulfur, which is found in fossil fuels, combines with oxygen to form SO2 when the fuel is burned. In GSU's case, the vast majority of SO2 emissions results from burning coal, although burning fuel oil can also produce SO2 emissions. The higher the sulfur content of the fuel, the more SO2 is produced. The amount of SO2 produced by a utility is directly linked to the sulfur content and quantity of the fuel burned. Ex. OPC-21 at 20.

utilities will participate in allowance transactions. Additionally, the EPA withholds 2.8 percent of a utility's allotted allowances for public sales and auctions. The EPA returns revenues from those auctions to the utility from which they were withheld. GSU's SO2 emissions allowance revenues during the reconciliation period were a result of the EPA auction of withheld allowances first available for use in the years 2000 and 2001. Ex. OPC-21 at 20-21. GSU received approximately $50,000 in revenues from the auction of its SO2 emissions allowances during the reconciliation period. Ex. OPC-21 at EP-6.

GSU accounted for its SO2 emissions allowance revenues in FERC Account 411.8, which is entitled: "Gains from Disposition of Allowances," which is included as utility operating income in the State of Income for the Year in FERC Form 1, 1994. GSU's position is that it recorded SO2 emissions allowance revenues in Account 411.8 because P.U.C. SUBST. R. 23.23 does not list revenues from emissions allowances as a reconcilable fuel item, and the Commission should not include such revenues in this fuel reconciliation.

OPC witness Ms. Pitchford does not agree with GSU's accounting treatment of SO2 emissions allowance revenues because GSU's treatment assumes that the FERC has prescribed base rate treatment of the revenues. 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." FERC Order No. 552 expressly provided that it was not intended to promote or discourage particular CAAA compliance strategies or to prescribe the ratemaking treatment for allowances. In other words, the final rule was intended to be "rate neutral," expressly leaving the proper accounting treatment of revenues from emissions allowances to be determined by the regulatory treatment ordered by the Commission.

The ALJ finds that P.U.C. SUBST. R. 23.23 defines eligible fuel costs according to FERC Uniform System of Accounts, as of September 30, 1992. The FERC's Order No. 552 which established accounting standards for SO2 emissions allowance revenues did not become effective until

January 1, 1993. The Commission has not expressly determined whether or not SO2 emission allowance revenues are reconcilable fuel revenues. Therefore, the ALJ agrees with Ms. Pitchford that FERC Order No. 552 is rate neutral and did not prescribe by its accounting treatment that SO2 emissions allowance revenues should be recorded in FERC Account 411.8 and treated in base rates only.

OPC witness Ms. Pitchford recommended that SO2 emissions allowance revenues be recorded in FERC Account 254 pending resolution of the issue by the Commission. In her opinion, the amount of GSU's emissions allowance revenues in this reconciliation period do not merit a complete analysis of the appropriate regulatory treatment of such revenues in this proceeding. Once there is regulatory certainty, GSU may then treat the approximate $50,000 in SO2 emissions allowance revenues received during the reconciliation period according to the Commission's directives. The ALJ agrees that recording GSU's $50,000 in SO2 emissions allowance revenues in FERC Account 254 would not only comply with FERC Order No. 552, but would allow both costs and revenues to be considered by the Commission at a future date. Therefore, the ALJ recommends that the Commission find that the relatively small amount of SO2 emissions allowance revenues received by GSU during the reconciliation period does not merit full consideration in this proceeding and that the issue should not be decided. GSU should, in the interim, record such revenues in FERC Account 254 instead of in Account 411.8. In this fashion, the Commission could in the future give consistent regulatory treatment to both SO2 emissions allowance revenues and costs.

D. Recovery of Lost Revenues Due to Theft of Electricity

In 1994, GSU initiated a program to recover lost revenues attributable to losses of electricity in both the commercial and industrial sectors. GSU witness Ms. Dolores Johnson testified that the program is designed to recover revenue lost for any reason, including from the theft of electricity. According to Ms. Johnson, during the reconciliation period, GSU identified and recovered approximately $1 million in lost revenues due to equipment failure, process failure, or theft. Ex. EGS-71 at 5.

Commission Staff witness Mr. Harold Hughes testified that the physics of electricity production and delivery necessarily results in some energy losses in the form of heat through conductors, transformers, and equipment. Current diversions, however, have nothing to do with the production and transmission of electricity, but are due instead to the theft of electricity. According to Mr. Hughes, GSU's system losses during the reconciliation period amounted to 2,543,009 MWh of electricity out of a total of 51,512,084 MWh generated. In Mr. Hughes' opinion, GSU's system losses were comparable to both the national average for major investor-owned utilities and adjacent utilities for 1994. Ex. GC-8 at 17.

However, because GSU did not adequately identify during discovery its revenue-recovery program or the revenues lost and recovered due to theft, Mr. Hughes concluded that GSU's current diversion program was not sufficiently aggressive. He therefore did not believe that GSU should receive any unrecovered revenues lost due to theft, recommending a $300,000 disallowance based on a comparison with Houston Lighting & Power Company (HL&P), which he described as GSU's neighboring utility. Ex. GC-8 at 18-19.

GSU witness Ms. Dolores Johnson adequately identified on rebuttal GSU's lost revenue recovery program and testified that she did not agree that Mr. Hughes' comparison of GSU with HL&P to assess GSU's loss recovery program was a valid comparison. Ms. Johnson explained that HL&P has a highly dense service territory, virtually all of which is in an urban setting, thus providing efficiencies of scale. GSU's service territory, in contrast, is much more rural. Additionally, prosecutions are an effective tool in recovery of lost utility revenues only in very limited situations, depending on the severity of the individual case. Ms. Johnson testified that GSU has adequate measures in place to address current diversion in its service territory and that its employees have been trained to investigate current diversion, take corrective action appropriate to the circumstances, and have been able to recover revenues lost due to theft. Ex. EGS-71 at 6-7.

The ALJ agrees and finds that GSU's current diversion and electricity loss program initiated in 1994 is reasonable and effective in recovering revenue lost due to theft of electricity. The ALJ does not agree that a comparison of GSU's current diversion program with that of HL&P is a valid comparison. The ALJ finds that GSU has adequate measures in place to detect current diversion and recover lost revenues for its diverse rural service territory. The ALJ finds GSU's approach of signing up prospective users of electricity as customers reasonable and finds that therefore the Commission Staff's recommended disallowance of $300,000 should be rejected. Therefore, the ALJ recommends that the Commission not make any disallowance for GSU's revenue losses due to theft of electricity during the reconciliation period.

XIII. Other Issues

A. What Are GSU's Reconcilable Fuel Expenses, Revenues, and Net Under-recovery?

The Commission General Counsel and Staff calculated and recommended that the Commission find GSU's reconcilable fuel expense for the reconciliation period to be $316,507,429, its revenues at $296,971,740, and miscellaneous adjustments of ($12,039), for a net fuel cost under-recovery for the reconciliation period of $20,452,982, as of June 30, 1995, without interest. Ex. GC-13A at Schedule B (Attachment E to PFD). The ALJ adopts General Counsel's calculation of GSU's reconcilable fuel expense, revenue, miscellaneous adjustments, and calculation of the net under-recovery for purposes of this reconciliation, noting that this assumes adoption of the Commission Staff's fuel allocation methodology as recommended by the ALJ and after certain corrections discussed in more detail below. Ex. GC-13A at Schedules B and C (Attachments E and F to PFD).

The ALJ therefore finds that GSU's reconcilable fuel expenses are $316,507,429; its revenues are $296,971,740; miscellaneous adjustments total ($12,039) for generation expense and purchase power true-ups; and therefore, GSU's net fuel cost under-recovery is $20,452,982 for the reconciliation period (as of June 30, 1995, without interest).

With interest as calculated by Commission Staff as of October 1996, the ALJ finds that GSU's cumulative fuel cost under-recovery is $22,894,943. Ex. GC-13A, Schedule A at 2 (Attachment D at 2, to the PFD). Additionally, with the exception of the recommended gas expense disallowance due to the motion for sanctions, the Staff's off-system sales allocation for the months of March and April 1994, and the recommended disallowance by Staff witness Mr. Hal Hughes due to lack of an aggressive electricity theft recovery program, the ALJ also adopts the General Counsel and Staff's calculation of the total disallowances and calculation of the under-recovery, as shown in Ex GC-13A, Schedule C at 1-2, (Attachment D to PFD), with certain corrections as discussed below.

B. Calculation of Under-recovery and the Staff's Surcharge Methodology

The Commission Staff calculated total disallowances of $12,541,771 applicable to GSU for the reconciliation period, and before interest, a total net under-recovery of $20,452,982 (without the recommended disallowance due to the motion for sanctions). Ex. GC-13A and Schedules B and C (Attachments E and F to PFD).

As of October 1996, the Commission Staff calculated a total net under-recovery, including interest, of $22,894,943. Ex. GC-13A, Schedule A at 2. The ALJ adopts the Staff and General Counsel's total net under-recovery of $22,894,943, with interest as of October 1996, and finds that figure accurately represents GSU's total net under-recovery with interest as of October 1996, subject to correction of Ex. GC-13A, Staff Schedule C at 2, being corrected to reflect allocation of off-system sales adders as 100 percent reconcilable as of April 28, 1994, as stated in the Preliminary Order.

1. Removal of Theft Disallowance and Addition of OPC Recommended Coal Disallowance.

The ALJ further finds that Staff and General Counsel's recommended total disallowances of $12,541,771 should be made by the Commission, but this amount should be corrected to account for the ALJ's rejection of the Staff's recommended $300,000 disallowance due to the absent theft loss recovery program on Staff Schedule Ex. GC-13A, Staff Schedule C at 2 (Attachment F), and the addition of the OPC's recommended coal cost disallowances of $317,000 due to overstated expenses of the calculated "pseudo-burn" at Big Cajun II, Unit 3.

2. Miscellaneous Expense Adjustments.

Staff witness Mr. Craig Archer testified that GSU adjusted Generation Expenses & Purchased Power Expenses, resulting in net amounts for these adjustments of $17 and $12,022, respectively. Mr. Archer recommended making the foregoing adjustments as timing adjustments, to reflect actual costs and adjustments in the applicable month. GSU's adjustments are reflected on Ex. GC-13A, Schedules CA-4 and CA-5 (Attachments I and J to the PFD). The ALJ finds that Mr. Archer's timing adjustments for these two categories of expenses are reasonable and recommends that they be made.

3. Docket No. 13170 Refund and Related Interest Calculation.

Staff witness Mr. Craig Archer also testified that in Docket No. 13170, GSU's last fuel reconciliation for the period October 1, 1991, through December 31, 1993, the stipulation resolving that case provided:

> For the purpose of this proceeding only, and in consideration of the settlement of all of the issues and disputes herein, and without conceding any claims, rights, arguments or positions, the Parties agree that the Amount at Issue to be recovered by Gulf States for the Reconciliation Period shall be resolved by:

(a) Gulf States paying a refund to customers of $2,817,550;

(b) reducing Gulf States' over/under-recovery balance, including interest, at December 31, 1993, to $0; and

(c) reducing the balance of interest payable to customers by Gulf States that is related to fuel over/under-recoveries for the months of October 1, 1991, through December 31, 1993, at December 31, 1994, to $0.

According to Mr. Archer, GSU made all three of the above-referenced refunds after December 31, 1994. Ex. GC-13 at 12. It was important for GSU to make the refunds before December 31, 1994, because on January 1, 1995, interest on the refunded amounts began to accrue. According to Mr. Archer, in May 1995, GSU made an entry on $50,091 to reflect the interest associated with the refund in Docket No. 13170, but the entry was not correct because the actual refund occurred over several months, therefore Mr. Archer recommended that the $50,091 in Docket No. 13170 refund related interest be removed. Ex. GC-13 at 13.

The ALJ agrees with Mr. Archer's recommendation and finds that the $50,091 in refund related interest be removed from consideration and that as shown in Staff Attachment CA-6, (Attachment K to the PFD), the actual amounts refunded in each respective month of refund should be incorporated into the determination of GSU's fuel under-recovery. By reflecting the actual refunds in the appropriate month, the Commission will ensure the correct over/under-recovery balance by month and will ensure the correct calculation and accrual of interest. Ex. GC-13 at Schedule CA-6.

4. Docket No. 10894 Refund.

According to Mr. Archer, at the end of October 1994, GSU's ending balance of the refund amounts ordered in Docket No. 10894 was under-recovered by ($779,971). GSU did not carry forward the refund balance from Docket No. 10894 and include that balance in this proceeding, which is the next fuel reconciliation after Docket No. 13170. Docket No. 10894 resulted in a refund of $34,514,393. Ex. GC-13 at 14.

Item No. 5 of the Stipulation and Agreement adopted in Docket No. 13170 provided that:

> The $2,817,550 refund referred to in Paragraph 4 above is a net figure agreed on by the Parties taking into consideration Gulf States' claimed under-recovery balance (including interest), Gulf States' over-recovery fuel and purchase power costs claimed by Cities, OPC, and General Counsel (including interest), and the Parties' joint intention to reconcile Gulf States' over/under-recovery balances at December 31, 1993, and related interest balance at December 31, 1994 to $0. The Parties agree that all interest payable or claimed to be payable on the Amount at Issue is covered by the refund amount. Notwithstanding the foregoing, unrefunded or over-refunded amounts from Docket No. 10894 and interest thereon will be carried forward and reconciled in Gulf States' next fuel reconciliation case.

Item No. 6 of the Stipulation Concerning Refund in Docket No. 10894 states: "Any over or under-refund amount existing at the end of the refund period or, at the end of the fifteenth (15) billing month (if additional refund is made in such month), will be carried forward into the Company's then-existing over/under-recovery fuel balance."

According to Mr. Archer, this transfer of the $779,971 over-refund amount from Docket No. 10894 did not occur until April 1996. Therefore, the ALJ adopts Mr. Archer's recommendation that the stipulation language in Docket No. 13170 be followed and that the $779,971 over-refund amount in Docket No. 10894 be carried forward into GSU's over/under-recovered fuel balance at the beginning of November 1994, (as calculated in Attachment L to the PFD).

5. Calculation of Surcharge.

The Commission Staff's and ALJ's recommendations result in a total under-recovered deferred fuel balance for GSU for the reconciliation period of $20,452,982, (without interest) as of

October 1996. With cumulative interest of $2,441,961, GSU's total under-recovered fuel balance is $22,894,943 as of October 1996.

Commission Staff witness Mr. Craig Archer recommended that GSU surcharge the under-recovered fuel balance, net of interest, in October 1996. Mr. Archer testified that he made his recommendation based in part on his determination that the fuel balance is materially under-recovered as defined in P.U.C. SUBST. R. 23.23(b)(2)(A)(iii)(II).[37] According to Mr. Archer, based on Texas retail eligible projected fuel costs of $232,636,597 as set in Docket No. 12852, GSU's under collection of $22,894,943 is equivalent to 9.5 percent, which exceeds the threshold limit of 4.0 percent. Further, GSU continues to be in a state of material under-collection. According to GSU's Fuel Cost Report for April 1996, GSU continues to have an under-recovered balance. Ex. GC-13 at 16.

The ALJ agrees with the surcharge recommended by Commission Staff and recommends that the Commission order GSU to surcharge its net under-recovery, net of interest, in the first monthly billing cycle following the Commission's Final Order in this proceeding. The ALJ finds that based on the Texas retail eligible projected fuel costs of $232,636,597 as set in Docket No. 12852, GSU's under collection of $22,894,943 is equivalent to 9.5 percent, which exceeds the threshold limit of 4.0 percent. The ALJ finds that GSU continues to be in a state of material under-collection, with its under-recovered fuel balance has almost doubled from GSU's fuel cost report for June 1995 and April 1996. Therefore, the ALJ recommends that the Commission order GSU to surcharge the total under-recovered fuel balance of $20,452,982 in the monthly billing cycle following the issuance of the final order in this docket.

37. That subsection provides that "..Materially or material, as used in this paragraph, shall mean that the cumulative amount of over- or under-recovery, including interest, is 4.0% of the annual estimated fuel cost figure most recently adopted by the Commission, as shown by the utility's fuel filings with the Commission." P.U.C. SUBST. R. 23.23(b)(2)(A)(iii)(II).

6. Cumulative Interest Balance.

Subject to correction by the Commission Staff based on the timing of the Commission's order in this docket, the ALJ finds that in accordance with the Staff's recommendation, GSU's cumulative under-recovered interest balance is $2,441,961 as of October 1996. Ex. GC-13A at 2. This represents a $1,511,204 increase to the Company's requested interest balance of $930,757 on a Texas jurisdictional basis. Ex. GC-13 at 17; and Ex. GC-13A at 2. Therefore, the ALJ recommends that the Commission find GSU's cumulative under-recovered interest balance as of October 1996 is $2,441,961, and recommends that amount be surcharged, subject to correction by Staff (Attachments D, M, N, O, and Q to the PFD).

XIV. Findings of Fact and Conclusions of Law

The ALJ respectfully recommends that the Commission make the following findings of fact and conclusions of law:

A. Findings of Fact

1. On December 7, 1995, Entergy-Gulf States, Inc., (GSU or the Company) filed an application with the Public Utility Commission of Texas (Commission) requesting approval of total fuel and purchased-power costs of approximately $318 million. All of GSU's customers in all areas served by it in Texas will be affected by this application.

2. With its application, GSU also requests authorization to defer the collection of its under-recovered fuel expense of $22,375,752, to be collected through a surcharge in a future proceeding. Alternatively, GSU proposes collection of its under-recovered fuel expenses through a surcharge of $22,275,752, less any Commission-authorized fuel cost disallowances, over a 12-month period.

3. GSU provided both published and direct mail notice of its application, as well as direct written notice to all of the parties in its last fuel reconciliation proceeding, *Application of Gulf States Utilities Company to Reconcile Fuel Costs,* Docket No. 13170, 20 P.U.C. BULL. 1026 (April 18, 1995) (mem.).

a. On January 31, 1996, GSU began providing published notice once a week for two consecutive weeks in newspapers of general circulation in each of the counties in its service area affected by the application. GSU completed published notice on September 4, 1996.

b. On February 6, 1996, GSU provided direct mail notice of its application to all of its retail customers in the form of an insert in monthly bills.

c. On June 4, 1996, GSU provided direct mail notice of its application to its large industrial customers affected by the application.

d. On August 14, 1996, GSU filed initial affidavits attesting that it provided published notice and direct mail notice to its retail customers, as well as direct written notice to the parties in Docket No. 13170.

e. On September 23, 1996, GSU filed revised affidavits attesting that published notice of its application had been completed.

4. The following parties intervened: Certain Cities[38] served by GSU (Cities); North Star Steel Texas, Inc., (North Star); Texas Industrial Energy Consumers (TIEC); the State of Texas; the Office of Public Utility Counsel (OPC); and the Commission's General Counsel. The State of Texas

38. The Cities include Port Neches, Groves, Nome, Vidor, Beaumont, China, Conroe, Port Arthur, and Nederland.

withdrew on July 17, 1996. TIEC did not actively participate in the hearing, but did monitor certain issues.

5. On January 9, 1996, the Commission transferred this case to the State Office Of Administrative Hearings (SOAH) to conduct a hearing and prepare a Proposal for Decision (PFD) with findings of fact and conclusions of law.

6. On January 22, 1996, the Administrative Law Judge (ALJ) held the initial prehearing conference and adopted a protective order. On February 5, 1996, the Protective Order was modified and adopted.

7. On February 26, 1996, the Commission issued the Preliminary Order, including issues to be addressed and areas not to be addressed at the hearing.

8. The hearing on the merits was convened on September 9, 1996, and concluded on October 8, 1996.

9. GSU voluntarily extended the one-year deadline in this case until January 31, 1997.

10. GSU, 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. GSU'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, GSU provides electric utility service to over 595,000 customers.

13. GSU owns four fossil-fuel powered generating plants, including two in Texas and two in Louisiana. Approximately 44 percent, or 2,410 megawatts (MW) of GSU'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. GSU'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 GSU'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. GSU 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 MW) and by Sam Rayburn G&T, Inc., (SRG&T) (accounting for 10 percent or 55 MW).

16. GSU also owns 42 percent, or 227 MW, of a coal-fired generating unit known as Big Cajun II, Unit 3, operated by the Cajun Electric Power Cooperative, Inc., (CEPCO), and located near New Roads, in Pointe Coupee Parish, Louisiana.

17. In addition to all of the foregoing generating capacity, GSU also owns a 70 percent share in the River Bend Nuclear Station, a Boiling Water Reactor (BWR) Nuclear Power Plant located near St. Francisville, Louisiana.

18. The Entergy Corporation (Entergy) is an investor-owned public utility holding company headquartered in New Orleans, Louisiana.

19. Entergy's five wholly-owned operating companies include Entergy-Arkansas, Inc., Entergy-Gulf States, Inc., (GSU), Entergy-Louisiana, Inc., Entergy-Mississippi, Inc., and Entergy-New Orleans, Inc. Collectively, the five Entergy Operating Companies (EOC) provide electric utility service to approximately 2.4 million retail customers.

20. The Federal Energy Regulatory Commission (FERC) approved the merger of GSU and Entergy, along with the corresponding Entergy System Agreement (ESA) amendment, effective January 1, 1994, in Opinion No. 385, *Entergy Service, Inc., and Gulf States Utilities Company,* 65 F.E.R.C. (CCH) Par. 61,332 (1993).

21. The Entergy System Agreement (ESA) is the contract that provides the basis for the joint planning and operation of the Entergy System, including the EOCs. The ESA governs the wholesale power transactions among the EOCs by providing for joint operation and establishing the basis for equalizing, among the EOCs, the costs associated with the construction, ownership, 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 GSU supplies GSU-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, GSU experienced significantly higher natural gas prices than the $1.85 per MMBtu forecasted price upon which GSU's fixed fuel factors in effect during the reconciliation period were based.

31. During the first eight months of the reconciliation period, GSU's actual system-weighted average natural gas prices ranged from $1.95 to $2.86 per MMBtu. During that time, GSU'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, GSU 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 GSU to reconcile, in calendar year 1995, its fuel and purchased power costs from January 1, 1994, and for the next twelve months thereafter. GSU filed the instant application on December 7, 1995, in compliance with the Commission's Order.

34. During the merger proceedings in Docket No. 11292, GSU 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 GSU's Texas jurisdictional share of the projected merger-related fuel savings.

35. In actual fact, GSU 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 GSU's Texas jurisdictional share.

36. GSU's actual merger-related fuel savings were not as high as Entergy and GSU 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 GSU's "PROMOD" computer model used to project merger-related fuel savings.

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

38. GSU'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, GSU'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 GSU's fuel cost under-recovery.

40. GSU'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 GSU's fixed fuel factors approved in Docket No. 12712.

41. Therefore, there is no correlation between the amount of GSU's fuel cost under-recovery during the reconciliation period and its projected merger-related fuel savings, because the under-

recovery was a function of GSU'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 GSU'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 GSU's fuel-cost under-recovery by any short-fall in projected merger-related fuel savings.

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

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

45. To the extent that GSU'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 GSU's customers on a proportionate basis if GSU allocated fuel costs on a proportionate basis.

46. GSU's Texas retail customers did not receive their fair share of the merger-related fuel savings because GSU 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 GSU's Texas retail fixed-fuel-factor

customers should result in those customers receiving a proportionate share of GSU's merger-related fuel savings.

48. GSU'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 GSU 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. GSU 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 GSU system whether or not that customer is billed for fuel on the basis of incremental or average fuel cost, GSU'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 jurisdiction its proportionate share of fuel costs, based on the fuel costs GSU 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 GSU's systemwide fuel costs are allocated to GSU's Texas retail fixed-fuel-factor customers than under GSU's methodology.

52. GSU 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 GSU 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 GSU subtracts the kWh sales and expenses incurred to serve that customer class from its fuel cost allocation methodology, i.e., GSU removes their usage and expenses from the fuel cost allocator utilized to impute or determine the fuel costs for GSU's customers.

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

57. Because GSU'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 GSU's system average fuel costs were greater than or less than its system incremental fuel costs.

58. During the reconciliation period, GSU'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 GSU include fuel costs imposed on the system by non-fixed-fuel-factor customers in both the Texas Retail Allocator and in the GSU 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 GSU'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 GSU's fixed- and non-fixed-fuel-factor customers during the reconciliation period.

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

62. GSU 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 GSU's natural gas costs during the reconciliation period included the role of natural gas in GSU's capacity and energy mix and the relevant markets in which the Company purchased its gas. Natural gas accounted for approximately 50 percent of GSU's energy mix during the reconciliation period.

64. GSU's long-term natural gas contracts provided for GSU's relatively extensive "swing" requirements during the reconciliation period. GSU's natural gas consumption during the reconciliation period generally followed the instantaneous energy demand of its customers. GSU's natural gas supplies must therefore be reliable and available in adequate volumes and in flexible ways to provide for the changes GSU 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 reconsiliation 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 GSU 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. GSU'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 GSU attempts to purchase the bulk of its short-term natural gas during bid-week, in reality, during the reconciliation period, GSU 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. GSU'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 GSU 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 GSU competitive long-term gas prices.

70. GSU'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, GSU entered into an agreement with SGT whereby SGT has the responsibility of providing GSU 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 GSU has first priority on capacity and deliverability of natural gas. SGT must obtain prior approval from GSU before entering into any third-party transactions.

72. Although GSU 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 GSU 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, GSU 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 GSU'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. GSU 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. GSU 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. GSU did permit SGT to market excess capacity in Spindletop to Koch, Centana, and Eastex Gas Marketing Companies during the reconciliation period.

79. GSU'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 GSU will likely require additional storage capacity in Spindletop in the future and that capacity will enable GSU to reduce its reliance on more expensive long-term and spot natural gas.

80. GSU'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 GSU's requirements were met and in light of the greatly diminished value of such services to third parties.

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

83. The price of this after-market gas purchased by GSU during the reconciliation period is determined by the relevant market for supply and transportation services for short-term gas at the time of the purchase. Therefore, the use of a first-of-the-month published index, such as *Inside FERC*, is inappropriate as a standard for judging the reasonableness of GSU's short-term gas purchases and expenses during the reconciliation period because it does not reflect market conditions that existed at the time of the transactions.

84. Further, a first-of-the-month published index does not adequately account for GSU's natural gas swing requirements, its operational constraints including the geographic location of its plants, peak demands for electricity, and transportation costs.

85. Although there was no reason for GSU to burn fuel oil instead of natural gas at GSU's Willow Glen Station in March 1994 because there was no gas curtailment at that time and the generating unit would have been derated, GSU 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 GSU 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. GSU 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 GSU 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. GSU'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 GSU'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. GSU was a party to the agreement.

96. GSU 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 GSU with a high degree of flexibility and reliability because they allow significant long-term gas supplies to be shifted between GSU'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 GSU 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 GSU'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 GSU's long-term contracts with Pontchartrain and SGDS.

101. GSU 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 GSU's coal costs were attributable to coal burned at GSU's Nelson Station, Unit 6, a coal-fired generating unit. The remainder of $33,707,201 in GSU's eligible coal costs were attributable to Big Cajun II, Unit 3, coal and displaced power costs.

103. The coal for GSU's coal-fired generating units is supplied under a long-term contract with Kerr-McGee Corporation (Kerr-McGee) from its mines in Wyoming. GSU 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. GSU 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 GSU's coal-fired generating plants. Neither of these long-term transportation agreements was amended during the reconciliation period.

105. GSU 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. GSU owns 42 percent of Big Cajun II, Unit 3, which is operated and owned in part by the Cajun Electric Power Cooperative, Inc., (CEPCO). GSU'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.