at RMG-6 through RMG-19. His recommendation would require that GSU purchase as much as 90 to 95 percent of its short-term spot gas during bid-week according to the monthly index, even though he admitted on cross-examination that the weight of other considerations, including system operational constraints such as swing, transportation charges, and fluctuating weather conditions must also be taken into account. Ex. EGS-61 at 27-28; Tr. Vol. XII at 2952-2954; 2974-2975. Cities' total recommended disallowance to GSU's short-term natural gas expenses totaled $3,473,207. Ex. Cities-83 at 23.

b. General Counsel's Recommended Natural Gas Expense Disallowance for GSU's Willow Glen Power Plant During March 1994

General Counsel witness and Commission Staff member T. Brian Almon, P.E., the Assistant Director of Fuel Analysis of the Commission's Industry Analysis Division, initially recommended a $666,377 disallowance in GSU's natural gas expenses representing the difference between the price of No. 6 fuel oil and the price of spot gas burned at GSU's Willow Glen Power Plant during March 1994. Ex. GC-12 at 19-22. Mr. Almon later revised his testimony and recommended disallowance downward to $62,958, based in part on a higher inventory price for No. 6 fuel oil at Willow Glen of $2.3145/MMBtu and a lower price for spot gas of $2.42/MMBtu (Koch Gas Services Company) and $2.60/MMBtu (Pontchartrain Natural Gas System) during March 1994. Ex. GC-12B.

GSU purchased 48,732 MMBtu of natural gas from Koch Gas Services Co. at $2.42/MMBtu and 136,327 MMBtu from Pontchartrain Natural Gas System at $2.60/MMBtu during March 1994. Because Mr. Almon did not see any documentation provided by GSU that would explain why GSU purchased spot natural gas above the cost of fuel oil inventory at Willow Glen in March 1994, he concluded that GSU was imprudent in purchasing natural gas from Koch and Pontchartrain instead of burning fuel from inventory. Ex. GC-12B at 1-2 (and attached workpaper). The total MMBtu available from fuel oil inventory at Willow Glen at that time was equivalent to the total 185,059

MMBtu of natural gas purchased at the higher price. General Counsel's total recommended disallowance in short-term natural gas expense for the difference is $62,958.

The ALJ finds that General Counsel adequately substantiated the Commission Staff's recommended disallowance for the short-term natural gas purchased for Willow Glen in March of 1994. Though the ALJ believes that there was no reason for GSU to burn fuel oil instead of natural gas because there was no gas curtailment at that time and that the generating unit at Willow Glen would have been derated if fuel oil had been burned, GSU had nevertheless burned fuel at those units very close to the time of the price differential between the gas and the fuel oil. Ex. GC-12 at 19. This demonstrates that operations could have made the switch and that the price differential was or should have been apparent. The ALJ finds that $62,958 represents the difference between the price of the fuel oil and natural gas at Willow Glen in March 1994, and recommends that this adjustment or disallowance be made to GSU's short-term natural gas expense for the reconciliation period.

c. ALJ's Recommendations Regarding GSU's Short-Term Natural Gas Expenses and General Counsel's Motion for Sanctions.

i. Whether Cities' proposed index is the proper standard of review for the reasonableness of GSU's short-term gas purchases during the reconciliation period?

GSU must purchase significant short-term gas on a daily and weekly basis after bid-week in response to changes in system operational conditions, customer demand for electricity, unanticipated changes in the availability of off-system economy energy, fuel supply and transportation constraints, and interstate pipeline tariffs and rules. On average, GSU purchases approximately thirty percent of its monthly short-term gas supplies after bid-week. Additionally, the amount of short-term gas GSU purchased *daily* during the reconciliation period varies significantly, based on the bidders' anticipation of market changes and the Company's anticipation of gas price variations in the short-term market. Ex. EGS -61 at 20-28; Tr. Vol. II at 480-481. The price of this "after-market" gas is determined by the relevant market for supply and transportation services *at the time of the purchase.* Ex. EGS-61 at 28.

GSU witness Mr. Amery J. Champagne, Entergy's President of System Fuels, testified that GSU purchases gas when it believes it is the optimum time to get the best price. He testified that it is sometimes necessary for GSU to buy gas in the daily market and that there are other gas requirements that GSU has that are not provided for by resort to the capacity in the Spindletop Gas Storage Facility. For example, Spindletop Gas Storage Facility does not serve GSU's Louisiana Plants, including the Willow Glen and Nelson Stations. Therefore, GSU is unable to swing those units on gas out of the Spindletop Storage Facility. Tr. Vol. II at 480-481.

Another constraint on GSU's purchasing the majority of its short-term gas requirements during bid-week is predicting the gas prices during the next month. Mr. Champagne testified that GSU takes the predicted market into account when considering gas volumes to be purchased during bid-week. Tr. Vol. II at 480-481. GSU cannot purchase all of its short-term gas needs during bid-week all of the time due to its swing requirements, the geographic location of its plants, and fluctuating gas prices.

The ALJ finds that Cities' proposed published first-of-the-month index plus a margin of \$0.03/MMBtu is not the proper standard of review for GSU's short-term gas purchases during the reconciliation period for several reasons. The ALJ finds that the use of a published index does not adequately account for GSU's swing requirements, operational constraints including the geographic locations of its plants, peak demands, and transportation costs. Cities' approach would require GSU to purchase over 90 to 95 percent of its short-term gas during bid-week, thereby cumulatively increasing the cost of GSU's short-term gas purchases without consideration of the other critical constraints. Ex. EGS-61 at 21; and WEH-2.

The ALJ finds that Cities' proposed index also does not account for the market conditions at the time a significant portion of GSU's short-term gas purchases were made. While some of GSU's long-term gas contracts may happen to be tied to an index, a significant portion of GSU's short-term gas contracts were not tied to a first-of-the-month published index. Tr. Vol. II at 494. GSU entered into over 2,000 short term transactions during the reconciliation period. Tr. Vol. VI at 1350. Cities selectively introduced approximately 60 examples of these short term contracts in an attempt to show that they could be made at a published, first-of-the-month index plus $0.03/MMBtu. Therefore, the ALJ finds Mr. Griffin's first-of-the-month index to be inappropriate as a standard for judging the reasonableness of GSU's short-term gas transactions in the daily and after-markets at the time they were made.

The ALJ further finds that the bulk of GSU's contracts could not be entered into at Houston Ship Channel or Henry Hub plus $0.03/MMBtu. Ex. EGS-25. The fact that GSU could enter into a contract at index plus $0.03/MMBtu is not proof that this benchmark is a reasonable standard. GSU can only negotiate and obtain prices of gas to the extent a seller is willing to provide gas at that price and prices in the daily market can change frequently. The Company solicits bids from as many suppliers as possible. Ex. EGS-61 (Harrington Reb.) at 18-19. The arbitrary nature of Cities' proposed index standard is demonstrated by Cities' unwillingness to give GSU credit for any advantageous price fluctuations due to gas purchased *below* the index prices.

GSU witness Mr. William Harrington presented a corrected analysis using an index approach, assuming an index would be a proper standard in the first place. For example, the Company used an index plus a $0.03/MMBtu adjustment for its Texas plants; use of the $0.03/MMBtu adjustment for Henry Hub or Louisiana transactions is not reasonable due to the fact that transportation to the Company's Louisiana plants is more expensive than to its Texas plants. Ex. EGS-61 (Harrington Reb.) at 33. Although the ALJ does not agree that a published index is a proper standard of review for GSU's short-term gas purchases, accurately reflecting the daily market price and an adjustment of $0.03/MMBtu for Texas plants and $0.08/MMBtu for Louisiana plants, GSU's short-term gas costs are reasonable. Under GSU's corrected index approach, assuming the Cities' index approach to prudence analysis were appropriate, no disallowance would be warranted. Ex. EGS-61 (Harrington Reb.) at 46-47 and Ex. WEH-5.

The ALJ finds that because the Cities relied on an inappropriate standard of review for GSU's short-term gas contracts, the recommended disallowances offered by Cities, OPC, NSS, and to the extent General Counsel adopted Cities' recommendations, should all be rejected. The ALJ finds that GSU demonstrated sufficiently that its short-term gas purchases were reasonable during the reconciliation period and that no disallowances should be made.

Finally, the ALJ finds that Cities', OPC's, NSS', and General Counsel's criticisms of GSU's gas management practices are unwarranted and without merit. GSU, through its witnesses generally, has shown that it purchases its short-term gas needs on the best terms and prices available in the market. Mr. Griffin's unsubstantiated criticisms of GSU in this respect are both unwarranted and unsupported.

ii. Whether General Counsel's motion for sanctions should be rejected for failure to comply with Procedural Rule 22.262?

The ALJ finds that because General Counsel's "motion" for sanctions does not comply with the basic procedural requirements and guidelines of P.U.C. PROC. R. 22.161(e), that it should be rejected. The ALJ believes that under the Commission Procedural Rules, a ruling on a motion for sanctions should require the conduct of a hearing and evidentiary findings, however the ALJ need not reach the merits of the motion since it does not comport with the basic requirements of P.U.C. PROC. R. 22.161(e).

Although General Counsel's brief is styled: "Initial Post-Hearing Brief and Motion for Sanctions," no separate motion for sanctions was filed. In its brief, General Counsel recommends that after notice and a hearing, the Commission should sanction GSU for deficiencies alleged to be reflected in GSU's response to Cities' RFI No. 24-1 by striking evidence offered by GSU and disallowing all expenses for short-term natural gas purchases during the reconciliation period over Cities' recommended index plus $0.03/MMBtu. General Counsel In. Brief at 33. General Counsel's recommended sanctions would result in a disallowance of approximately $8.5 million. Therefore, General Counsel requests that the reasonableness of the short-term gas purchases not be judged on the basis of whether they were reasonable, but be summarily disallowed as a sanction based on alleged discovery abuses.

Under P.U.C. PROC. R. 22.161(e), a motion for sanctions is required to: (1) contain all factual allegations necessary to apprise the parties of the conduct at issue; (2) request specific relief; and (3) be verified by affidavit. The ALJ agrees with GSU that General Counsel's request does not meet the procedural requirements for a motion for sanctions because the factual allegation necessary to apprise the parties of the conduct at issue is not clearly stated and is not verified by affidavit as required by the rule. Additionally, the ALJ does not believe that the relief requested is shown to be warranted by the allegations, nor is it specifically stated as required by P.U.C. PROC. R. 22.161(e). Therefore, the ALJ recommends that the Commission reject General Counsel's motion for sanctions because it does not comply with the rule. There is therefore no need to reach the merits of the motion and no need for a hearing.

4. GSU's Pontchartrain and Spindletop Gas Distribution System (SGDS) Long-Term Contracts.

A more developed short-term gas market during the reconciliation period did not necessarily mean that GSU could live with decreased swing or flexibility in its long-term gas contracts. Ex. EGS-61 at 12-13. The flexibility and reliability of the Pontchartrain and SGDS agreements provided 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. Both the agreements were signed in 1984 and amended in 1991. Both agreements provide highly reliable, flexible gas supply services and contain supplier's Weighted Average Cost of Gas (WACOG) price terms, plus a seller's margin. The supplier's WACOG is capped by a gas market index and a fuel oil alternative price ceiling giving the seller an initiative to offer competitive long-term gas prices. Both contracts contain seller's margins equal to \$0.31/MMBTU. Ex. EGS-61 at 44-46.

a. Cities Recommended Disallowance for GSU's Long-Term Pontchartrain and SGDS Contracts.

In Mr. Griffin's opinion, the GSU-Pontchartrain contract, a long-term take or pay contract with a price mechanism based on the seller's WACOG plus a margin of \$0.31/MMBtu, was among the highest priced gas purchases made by GSU during the reconciliation period. According to Mr. Griffin, the high price of Pontchartrain gas was due mainly to the seller's WACOG plus \$0.31/MMBtu margin price mechanism. Mr. Griffin testified that at the time the Pontchartrain contract was entered into, a reasonable pricing mechanism would have been a market sensitive index such as *Inside FERC*, at the Houston Ship Channel, in Houston, Harris County, Texas, or the Henry Hub, in Louisiana, rather than seller's WACOG. Ex. Cities-83 at 18-19.

Mr. Griffin also testified that the \$0.31/MMBtu seller's margin in the Pontchartrain contract was excessive. In Mr. Griffin's opinion, there is no apparent service provided in the contract that would justify a seller's margin of \$0.31/MMBtu. Although he acknowledged the swing capability provided by the Pontchartrain contract, in his opinion, that capability was in excess of GSU's requirements and did not warrant a seller's margin of \$0.31/MMBtu. Mr. Griffin proposed an adjustment he thought was consistent with market conditions at the time the Pontchartrain base contract was entered into on November 1, 1991, specifically, a market sensitive price plus a reasonable margin. Mr. Griffin's proposed pricing mechanism was based on the *Inside FERC* market index at Henry Hub, plus a $0.15/MMBtu seller's margin. In his opinion, the $0.15 margin is a reasonable price for swing service.[13]

For the SGDS long-term contract, which became effective on January 1, 1994, Mr. Griffin testified that although the pricing mechanism was also based on seller's WACOG plus a $0.31/MMBtu margin, during the reconciliation period the price actually paid by GSU was based on the *Inside FERC* Houston Ship Channel index plus a margin, agreed to on a verbal basis. As with the Pontchartrain base contract, Mr. Griffin considered the seller's margin on this contract unreasonably high. Mr. Griffin proposed an adjustment reflecting the *Inside FERC* Houston Ship Channel index price plus a margin of $0.15/MMBtu. Mr. Griffin recommended total disallowances or adjustments to GSU's long-term natural gas contract expenses for the reconciliation period of $7,743,632. Ex. Cities-83 at 20-21.

b. ALJ's Recommendations Regarding GSU's Long-Term Natural Gas Expense.

i. Whether the Pontchartrain Swing Contract is subject to review in this fuel reconciliation after Docket No. 13170?

The Pontchartrain swing contract was effective November 1, 1991, and was subject to a previous fuel review in Docket No. 13170, *Application of Gulf States Utilities Company to Reconcile Fuel Costs,* 20 P.U.C. Bull. 1026 (Apr. 18, 1995) (mem.) (Conclusion of Law No. 6). Therefore, GSU argues that the window of opportunity to review the Pontchartrain swing contract occurred during the reconciliation period covered in Docket No. 13170. GSU further argues that the Commission has determined that only the administration of contracts can be reviewed in proceedings subsequent to the period a previously reviewed contract is negotiated and executed. Docket No. 9030, *Petition of General Counsel for a Fuel Reconciliation for Southwestern Public Service Company,* 17 P.U.C. Bull. 395, COL No. 9 (June 3, 1991) (Consistent with the doctrines of res

13. Mr. Griffin proposed the same adjustment for the Pontchartrain swing contract, including the same pricing mechanism adjustment based on the Henry Hub spot-gas price, plus a seller's margin of $0.15/MMBtu for swing service. The Pontchartrain swing contract was also entered into on November 1, 1991.

judicata and collateral estoppel, the Commission determined that under the fuel rule only the administration of previously considered fuel contracts and not the prudence of the underlying terms could be subject to review).

The doctrine of *res judicata*, frequently characterized as "claims preclusion," bars litigation of all issues connected with the cause of action or defense, which, with the use of diligence, might have been tried in the prior suit. *Bonniwell v. Beech Aircraft Corp.*, 663 S.W.2d 816, 818 (Tex. 1984). When a prior judgment is offered in a subsequent suit in which there is identity of parties, issues and subject matter, the judgment constitutes an absolute bar to retrial of claims pertaining to the same cause of action on the theory that they have merged into the judgment. *Bonniwell,* 663 S.W.2d at 818.

GSU argues that the application of the doctrine of *res judicata* to this case is entirely consistent with the Texas Supreme Court's expressed awareness of the "usefulness of *res judicata* in administrative proceedings," and its "strong preference that 'continued litigation of issues or piecemeal litigation should be discouraged' in state regulatory agencies." *Coalition of Cities v. Public Utility Comm'n,* 798 S.W. 2d 560, 563 (Tex. 1990); *and* Docket No. 12855, *Application of Southwestern Electric Power Company to Reconcile Fuel Costs,* 20 P.U.C. Bull. 843, at 864-65 ("[O]nce the Commission has reviewed the prudence of the original prices, terms, and conditions of a fuel contract in a fuel reconciliation proceeding, *res judicata* precludes the reconsideration of such in a subsequent proceeding.")

Collateral estoppel or "issue preclusion" bars re-litigation of any ultimate issue of fact actually litigated and essential to the judgment in a prior suit, regardless of whether the second suit is based upon the same cause of action. *Bonniwell,* 663 S.W.2d at 818. The party seeking to invoke the doctrine of collateral estoppel must establish:

(1) The facts sought to be litigated in the second action were fully and fairly litigated in the prior action;

(2) Those facts were essential to the judgment in the first action; *and*

(3) The parties were cast as adversaries in the first action. Id. at 818. (emphasis added)

While the ALJ tends to agree with GSU that the contents of Docket No. 10894 (EGS Ex. 34A) may show that the issue of the reasonableness of GSU's nuclear fuel costs was fully and fairly litigated in that proceeding and that no party contended that it was deprived of the opportunity to introduce evidence or testimony on those issues, the ALJ believes that the argument is not entirely dispositive of the reasonableness of GSU's Pontchartrain Swing contract. The ALJ finds that Docket No. 13170 was a stipulated, or settled fuel proceeding, while the doctrine of collateral estoppel applies to facts "...that were fully and fairly litigated in the prior action." Because the reasonableness of the Pontchartrain swing contract was not fully and fairly litigated in Docket No. 13170, the findings of reasonableness in that proceeding do not act to collaterally estop the Commission's review of the prudence of that contract in a litigated proceeding.

Additionally, the specific terms of the stipulation in Docket No. 13170 reserved the issue for consideration in a later proceeding. In other words, rather than just the typical non-precedential language usually included in Commission orders, the stipulation specifically found that the issues agreed to and the Commission's findings thereon were subject to consideration in later proceedings. Therefore, the ALJ finds that the findings in Docket No. 13170 do not automatically remove the Pontchartrain contract from a reasonableness or prudence review in this proceeding. Nevertheless, the ALJ finds that the Pontchartrain Swing contract is reasonable for the reasons discussed below with reference to the Pontchartrain base contract.

ii. Whether the Pontchartrain and SGDS Contracts are reasonable based on the surrounding circumstances at the time, considering the swing, reliability, and degree of flexibility, they provide?

GSU signed the Pontchartrain and SGDS long-term gas supply agreements in 1984 after an earlier Exxon USA agreement became less economical. Ex. EGS-61 at 37-42. An important consideration in entering the Pontchartrain and SGDS contracts was the ability to shift gas supply volumes between GSU's Willow Glen plant, located in Louisiana, and GSU's Texas power plants, providing a high degree of flexibility, reliability, and swing.

GSU's position is that the Pontchartrain and SGDS long-term gas contracts provide GSU with the highest degree of flexibility and reliability. Flexibility and reliability are necessary in its long-term gas contracts to allow the Company to maintain electric system reliability and participate actively in the short-term natural gas markets. GSU concedes that the costs involved in these contracts are higher than in short-term contracts because the service levels, including reliability and swing, involved are higher than those found in the short-term market. GSU also points out that the cost of the Pontchartrain and SGDS gas supplies are less than comparable intrastate transportation services. GSU argues that the costs of the Pontchartrain and SGDS long-term gas supplies are reasonable and should be included as reconcilable fuel costs for the reconciliation period. Ex. EGS-61 at 47.

The ALJ finds that GSU's long-term contracts negotiated with a WACOG pricing mechanism -- the Pontchartrain and Spindletop contracts -- are reasonable. The ALJ finds that at the time these contracts were negotiated, WACOG was an appropriate measure to price these long-term contracts entered into 1984. The Cities' attempt to discredit these long-term contracts by comparing them to other firm contracts is not a proper comparison. The other firm contracts were entered with a WACOG adjustment and were only recently modified to an index after negotiations between the parties. Tr. Vol. XVII at 4188-4193. At the time the Company entered into the Spindletop and Pontchartrain agreements, as well as these other firm agreements, the pricing mechanism in the industry was the WACOG. Ex. EGS-61 (Harrington Reb.) at 41-43.

Moreover, the Spindletop contract, which is identical to the Pontchartrain contract, was originally executed in 1984. As Mr. Harrington explained, the Spindletop contract was changed from WACOG to an index when it was renegotiated. When a new owner purchased the pipeline, this new supplier wanted to deliver gas in Texas through the Tejas Pipeline; it therefore requested in negotiations that an index plus a margin be utilized. Tr. Vol. XVIII at 4419-4421. This contract became effective on January 1, 1994.

Cities attempted to apply an improper standard of review to the pricing terms of GSU's long-term contracts: a published index plus a \$0.15/MMBtu margin. To now attempt to review the reasonableness of these long term contracts based on an index that was not in existence at the time of the contracts would be an improper standard of review. Ex. EGS-61 at 41-43. The ALJ rejects Cities' attempt to apply an improper standard and finds that the appropriate standard of review for a fuel reconciliation should focus on the circumstances that existed at the time the agreements were negotiated, not simply an index related to price to the exclusion of all other terms and circumstances.

The ALJ also rejects Cities' witness Mr. Griffin's attempt to apply an arbitrary margin of \$0.15/MMBtu because he did not adequately justify such a margin. In an attempt to support a recommended index plus a \$0.15/MMBtu margin, the Cities urge a number of arguments, including the comparison of other utilities' contracts. These comparisons, however, are not valid for a number of reasons.

For example, the so-called seasonal swing contracts are not comparable to GSU's Pontchartrain and Spindletop contracts. The Onyx, Trebor, and Delhi contracts were all seasonal summer swing contracts. Summer swing contracts are cheaper because gas prices are cheaper during the summer. Tr. Vol. XVII at 4201-03. The ALJ believes that the degree of swing found in these contracts does not come close to the degree of swing found in the Pontchartrain and Spindletop contracts. Seasonal swing contracts are interruptible; in contrast, firm contracts such as the Pontchartrain and Spindletop contracts are not.

Additionally, the ALJ finds that a comparison of GSU's long-term contracts with the "long-term contracts of other utilities" is not relevant to judge the reasonableness of the GSU's long-term contracts. The ALJ finds that other utilities' long-term contracts cannot serve as the basis to evaluate the reasonableness of GSU's long-term contracts because different long-term contracts may differ in terms other than just price. Tr. Vol. V at 1270.

For example, the swing ratio available under the contracts of Texas Utilities Electric Company ("Texas Utilities") is significantly less than that found in the Pontchartrain and Spindletop contracts. The swing ratio for the Tenngasco contract is 3 to 1, while the swing ratio in the Pontchartrain contract is 20 to 1. Tr. Vol. XIII at 3075-3080. Moreover, the delivery points in the Texas Utilities contracts are to the pipeline. Tr. Vol. XIII at 3081-82; and Ex. EGS-48. The delivery points in GSU's contracts are to its plants. Tr. Vol. VI at 1532-33; Ex. EGS-61 (Harrington Reb.) at 38. The ALJ agrees that what other utilities are paying for long-term gas is not dispositive of the determination of the reasonableness of the GSU's long-term gas contracts. GSU In. Brief at 43-48.

Therefore, because the ALJ finds that Cities' recommended application of an improper standard of review to the Pontchartrain, Pontchartrain Swing, and SGDS long-term contracts should be rejected and does not comport with the standard of review for a fuel reconciliation, the ALJ finds that Cities' recommended disallowances to GSU's long-term gas contracts should also be rejected. No Commission Staff member recommended any unreasonable or disallowable expense in connection with GSU's long-term gas contracts. The ALJ finds that GSU adequately demonstrated the reasonableness of the long-term Pontchartrain, Pontchartrain Swing, and SGDS contracts and expenses under the prudence standard for reasonable fuel reconciliation expenses and that the expenses under these contracts during the reconciliation period are reasonable and necessary reconcilable fuel expenses.

5. ALJ's Recommendation Regarding GSU's Marketing of Excess Capacity in the Spindletop Natural Gas Storage Facility.

a. **To what extent did GSU seek to market excess capacity at its Spindletop natural gas storage facility to third parties during the reconciliation period in an effort to reduce fuel costs for GSU's ratepayers; and, were GSU's efforts in this respect reasonable?** (Preliminary Order Issue No. 4)

GSU's natural gas acquisition strategy of maximizing gas purchases from spot gas supplies allows the Company to take advantage of a swing transportation agreement with Sabine Gas Transmission Company (SGT) and off-system power purchase opportunities. On August 1, 1991, GSU entered into an agreement with SGT whereby SGT has the responsibility for providing natural gas transportation services, delayed transportation services, swing service, and storage capacity in return for a transportation fee.

b. **The Sabine Gas Transmission Company Transportation Agreement and the "Spindletop" Storage Facility.**

The "Spindletop" storage facility is located in the original 1900's era oil-well formation located near Beaumont, Texas. Tr. Vol. II at 513. The storage facility cavern became commercially operational in November of 1992. GSU completed development of a second storage cavern with approximately 5.4 billion cubic feet (bcf) total capacity in March of 1994. Commercial operation of the second cavern commenced in August of 1994. Upon completion of the second storage cavern, SGT began to enlarge the first storage cavern in accordance with the agreement. The first cavern is projected to be enlarged to a total capacity of 7.4 bcf and to be ready for service by December 1996. Ex. EGS-9 at 10-11. The SGT 14-mile pipeline connecting the Sabine generating station to the "Spindletop Gas Storage Facility" is completely operational. Ex. EGS-9 at 11; and Ex. EGS-1, Schedule FR-7 at 2.

GSU does not, however, own the Spindletop storage facility. Tr. Vol. II at 513. In order to provide transportation services to GSU under the terms of the SGT agreement, SGT committed the entire capacity of the facility to GSU's use. SGT's legal rights to market the unused capacity of the Spindletop facility are limited by the SGT agreement. Under the agreement, GSU has first priority on the capacity and deliverability from the facility and SGT must obtain prior approval from GSU to enter into third-party transactions. Under the agreement, GSU may release unused capacity back to SGT for marketing to third parties. Ex. EGS-10 at 2-4.

During the reconciliation period, SGT (not GSU) received approximately $488,602.15 in third-party net revenues for third-party transactions in the Spindletop Facility, to the extent any excess capacity was available for third-party use. Tr. Vol. VI at 1472. After the reconciliation period, SGT received an additional $47,973.32 in third-party revenues, for total reconciliation period transaction revenues of approximately $536,575.47. Tr. Vol. VI at 1474. All net revenues, defined as revenue less electricity expenses and operation and maintenance expenses, derived from third-party transactions must be immediately credited to reduce the "pay-off amount" owed by GSU to SGT under the terms of the agreement. Tr. Vol. VI at 1476. Reducing the "pay-off amount" effectively lowers the reconcilable fuel expenses incurred by the GSU customers under the agreement by accelerating the reduction of the SGT transportation fee.

Further, the value to third parties of SGT's storage services is limited by: (1) the period when storage capacity is available for release to third parties and (2) the geographic proximity of the storage facility to gas market centers. Ex. EGS-10 at 4. GSU generally needs most of the capacity provided under the SGT agreement during the late spring through the early winter months. Therefore, the value of SGT's services to third parties was greatly diminished during the greater part of the reconciliation period. The primary value of salt dome gas storage is a utility's ability to maintain reliable gas supplies during winter peaking periods. Ex. EGS-10 at 4-5.

c. **GSU Reasonably Released Excess Capacity in the Spindletop Storage Facility to the Extent Any Excess Capacity Existed.**

To the extent excess capacity was available for third party transactions at SGT's Spindletop storage facility during the reconciliation period, the ALJ finds that GSU reasonably and prudently sought to market such excess capacity to third parties to the extent the value to GSU ratepayers of such third-party transactions for SGT's services exceeded the value of SGT's services to GSU. During the reconciliation period, the ALJ finds that GSU reasonably evaluated whether its ratepayers would obtain greater value from the third party transaction with SGT than if GSU had utilized SGT services and capacity available to GSU. Ex. EGS-10 at 6. No party in the proceeding recommended and supported through evidence any disallowance of third-party revenues relating to gas storage capacity in Spindletop or for SGT's transmission services for the reconciliation period; rather the issue is the reasonableness of crediting such revenues to ratepayers through indirect credits against the payoff amount under the terms of the agreement. Tr. Vol. II at 509.

The ALJ finds that there was little unused capacity available for third party transactions in the Spindletop storage facility. During the first six months of the reconciliation period, SGT made approximately 800,000 MMBtu of working gas capacity available to GSU. During the last twelve months of the reconciliation period, SGT made approximately 2,700,000 MMBtu available for GSU's use. GSU needed approximately 1,000,000 MMBtu during the reconciliation period for operational purposes, for maintenance of system reliability and flexibility. Additionally, GSU needed approximately 1,500,000 MMBtu to 1,700,000 MMBtu of working gas capacity for seasonal price arbitrage during the fall and through the mid-winter months.[14] Ex. EGS-10 at 6-7.

14. For example, during the first ten months of the reconciliation period, the Spindletop facility only consisted of a single 1.5 bcf capacity storage cavern and GSU used almost all of that capacity to fuel its Sabine power plant. Tr. Vol. VI at 1546. The second storage cavern was rated at a capacity of 5.4 bcf and was not available until November 1994 for the last eight months of the reconciliation period for a total of approximately 6.9 bcf, but also GSU needed substantially all of that capacity for its Sabine power plant, which used an average of 110 bcf a year during the reconciliation period. GSU required almost all of the additional storage capacity provided by the second cavern to account for its seasonal winter peaking demands. Tr. Vol. VI at 1548.

To the extent any unused capacity existed in the Spindletop storage facility for third party transactions during the reconciliation period, the ALJ finds that GSU reasonably and prudently sought to market such excess capacity to third parties under the terms of the agreement. Commission Staff witness Mr. T. Brian Almon testified that during the reconciliation period, GSU did allow Koch, Centana, and Eastex Gas Marketing Companies to use the services of the Spindletop natural gas storage facility. He testified that third-party utilization constituted 15 percent of the injections and 19 percent of the withdrawals in the Spindletop storage facility. From the information he reviewed, Mr. Almon testified that although he could not determine if more capacity in Spindletop could have been marketed during the reconciliation period, he determined that under the transportation agreement with SGT, GSU does not receive directly any part of the third-party revenues from excess capacity in Spindletop. Under the terms of the agreement as amended in 1991, all third-party revenues are to be credited against the payoff amount as long as the payoff amount is greater than zero. The payoff amount was greater than zero during the reconciliation period. Mr. Almon concluded that GSU's efforts to market the excess capacity in Spindletop to third parties during the reconciliation period was reasonable. Ex. GC-12 at 14-15.

The ALJ finds that the value of third party transactions in Spindletop storage facility services during the reconciliation period was diminished due to the fact that very little such excess capacity was available to release to third parties and by the geographic proximity of the storage facility to gas marketing centers where third parties would have to take delivery of the gas. Ex. EGS-10 at 4. The nearest accessible gas marketing centers in relation to SGT's facilities are the Katy Hub in Waller County, Texas, and the Houston Ship Channel, near Houston, Harris County, Texas. Because both of these marketing centers are not directly connected to SGT's facilities, the value of SGTs' services to third parties is diminished by the added transportation costs that would be incurred to transport the gas from SGT's facilities to the marketing centers. Ex. EGS-10 at 5.

To the extent that third party transactions in Spindletop were conducted during the reconciliation period, the ALJ believes that SGT's use of the net revenues from these transactions to off-set the pay-off amount under the SGT agreement was reasonable in light of the high value of the SGT storage facility and agreement to GSU. Ex. WEH-1, EGS-10 at 1-2 (Confidential Revenue and Quantity Schedule). Based on the evidence, the Commission could infer that the value of SGT's services to GSU, and thus to its ratepayers, including any available capacity in the Spindletop storage facility under the agreement, exceeded the value of such services to third parties during the reconciliation period, due to the significantly reduced value of third party transactions. GSU's off-set of the "pay-off amount" under the agreement with net revenues from third party transactions is reasonable because GSU will likely require additional capacity in Spindletop in the future. Ex. EGS 10 at 4-7. The ALJ finds that the expanded capacity in Spindletop will help and has already helped GSU reduce its reliance on more expensive long-term contracts in the future, thus reducing natural gas costs to ratepayers. Tr. Vol. VI at 1485-1487.

B. Coal Costs

GSU had a total of approximately $94,552,504 in eligible coal costs for the reconciliation period. Ex. EGS-1 at Schedule FR-16.1; and Ex. GC-12 at 6. Of the total reconcilable 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. Ex. GC-12 at 7. The remainder of $33,707,201 in coal costs were attributable to Big Cajun II, Unit 3, coal and displaced power costs.

The ALJ recommends the following disallowances be approved: $317,100 for Big Cajun II, Unit 3, on a Texas retail basis, as recommended by OPC; and $788 in total expenses representing the difference in the Nelson spot coal purchase and market prices, as recommended by General Counsel.

1. Coal Costs Attributable to Nelson Station, Unit 6.

GSU owns and operates approximately 70 percent of the Nelson 6 coal-fired generating unit located near Westlake, in Calcasieu Parish, Louisiana. Nelson 6 is a 550 MW coal-fired unit that has no natural gas-burning capability. GSU's 70 percent share of Nelson 6 accounts for approximately 385 MW of the unit's rated generating capacity. The remaining 30 percent or 165 MW is owned in part by the Sam Rayburn Municipal Power Agency (SRMPA), which owns 20 percent or 110 MW, and Sam Rayburn G&T Inc. (SRG&T), which owns 10 percent or 55 MW. Ex. EGS-18 at 4; and Ex. GC-12 at 9.

The coal for GSU's coal-fired generating units is supplied by the Kerr-McGee Corporation (Kerr-McGee) from its mines in Wyoming under a long-term contract with GSU. GSU also purchased approximately 7,884 tons of spot coal from Kerr-McGee during the reconciliation period. Additionally, GSU has entered into a long-term transportation agreement with the Burlington Northern and Kansas City Southern railroads for delivery of the coal from Kerr-McGee. Neither of these long-term agreements was amended during the reconciliation period. Ex. GC-12 at 9.

a. GSU's Spot Coal Purchase for Nelson 6.

In December 1994, GSU purchased 7,884 tons of spot coal from Kerr-McGee for Nelson Unit 6 at a price of $4.15/ton (or $0.2413/MMBtu). Under the terms of the spot coal letter agreement, Kerr-McGee agreed to deliver up to 150,000 tons of coal at the $4.15/ton price. GSU did not seek bids from any coal suppliers other than Kerr-McGee. GSU's stated reason for not soliciting other bids is that it knew the conditions of the spot market from published sources such as *Coal Week*, and that it relied upon a reported spot bid of $4.43/ton for 1995 deliveries of coal to the Lower Colorado River Authority (LCRA). Because the Kerr-McGee bid for spot coal was lower than the LCRA bid, GSU believed that the bid was the lowest reasonable price for spot coal. Ex. GC-12 at 23.

General Counsel, through Commission Staff witness Mr. T. Brian Almon, was the only party to analyze GSU's coal costs for Nelson Station, Unit 6, and the long-term coal costs for Big Cajun. Adoption of the General Counsel's recommendations results in a disallowance of $788 for the Nelson 6 spot coal purchase at higher than market price. Mr. Almon testified that in his opinion GSU could have obtained a lower bid if it had solicited bids from other Wyoming coal producers. According to Mr. Almon, the October 3, 1994 issue of *Coal Week* reported that Grand Island Nebraska purchased spot coal from the Caballo Rojo Mine for $4.05/ton (or $0.2411/MMBtu). It is common knowledge in the coal business, according to Mr. Almon, that bids made to public utilities like Grand Island Nebraska and the LCRA will be higher than bids made to investor-owned utilities like GSU, who are not required to reveal the bids. Additionally, for October, November, and December 1994, *Coal Week* also reported that the marker price for 8,400 Btu/lb. coal from Wyoming was $4.05 per ton.

The ALJ agrees with Mr. Almon in his conclusion that GSU was not prudent in its decision to purchase coal without bidding and should have solicited bids from all of the coal suppliers served by the Burlington Northern Railroad in Wyoming and taken the lowest bid for the spot coal purchased in December 1994. Mr. Almon therefore recommended that $788 in GSU's coal costs for Nelson Unit 6 for December 1994 be disallowed, representing the difference in the total expense of the 7,884 ton spot coal purchase at $4.15/ton and the amount the same purchase would have cost at $4.05/ton. Ex. GC-12 at 24-25. GSU witness Mr. Roy Giangrosso testified on rebuttal that GSU would have had to purchase an additional 235 tons of the lower Btu coal to obtain an equivalent supply. Ex. EGS-59 at 12. However, Mr. Giangrosso acknowledged that the bids made to public utilities like the LCRA are generally higher than those made to investor-owned utilities like GSU.

The ALJ finds that GSU should have solicited bids for its spot coal purchase in December 1994. The spot coal purchase should have reflected market prices at the time of the purchase. Ex. GC-12 at 7. Consequently, the market price for the total spot coal purchase for Nelson 6 during the reconciliation period was $31,930.20. Because GSU did not solicit bids, the ALJ agrees with Mr. Almon that the Commission should disallow the expense of $788, the difference between the market price of the coal and the $32,719 expenditure made by GSU and recommends that the Commission exclude the expense as imprudent and not a reasonable coal expense.

b. GSU's Long-Term Coal Purchases for Nelson 6.

GSU's portion of long-term coal purchases at Nelson 6 is 2,383,251 tons or 40,231,501 MMBtu for the reconciliation period, representing total reconcilable expense of $60,812,584. GSU purchased this long-term coal under contract with Kerr-McGee. Commission Staff witness Mr. T. Brian Almon concluded that GSU's long-term coal purchases for Nelson 6 were reasonable and he recommended that GSU's total Nelson 6 long-term coal expenses of $60,812,584 be allowed and reconciled. Ex. GC-7 at 26.

c. The Nelson Rail-Spur.

GSU did not include any expenses in its reconciliation related to the rail spur that is being built to the Nelson Station. GSU originally intended to complete the spur in 1995, but delayed its completion because it believed that the lower transportation rate to justify the construction of the spur was not available from the railroad companies, although GSU received no written bids for transportation rates. The issue, however, is whether GSU could have lowered the cost of coal to Nelson if it had completed the rail spur during the reconciliation period. Ex. GC-12 at 27.

The railroads, including GSU's existing carriers, did not bid for several reasons. The Burlington Northern and Kansas City Southern, one of the railroads supplying coal services transportation to Nelson 6, already had a contract rate for transporting coal to Nelson 6. The Burlington Northern Railway had offered a reduced rate in August 1994 that would have lowered the cost of delivering spot coal to Nelson. The Union Pacific and Chicago Northwestern Railroads declined to bid because they could not handle the extra tonnage. Ex. GC-12 at 28.

Although GSU never received the equivalent of a written bid containing the rate used to justify the construction of the Nelson rail spur, it received verbal assurances from railroads that deliveries could be made over the Union Pacific/Southern Pacific railroads at a substantial savings over existing rates. Mr. Almon therefore recommended that unless GSU shows complete and credible documentation that the Nelson rail spur is a benefit to ratepayers, GSU should not be allowed to pass on any expenses associated with the spur either in fuel or base rates. The ALJ finds, as Mr. Almon concluded, that the use of an estimated transportation rate to justify a several million dollar rail spur is not prudent management. Ex. GC-12 at 27-28. The ALJ therefore recommends that unless GSU shows complete and credible documentation that the Nelson rail spur is a benefit to ratepayers, GSU should not be allowed to pass on any expenses associated with the Nelson rail spur in fuel or base rates. The ALJ recommends that the Commission order GSU to make such credible documentation in its next base rate and fuel reconciliation filings at the Commission.

2. GSU's Big Cajun II, Unit 3, Coal and Displaced Power Costs.

GSU owns 42 percent of the Big Cajun II, Unit 3, Station (Big Cajun) 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 Unit 3, with CEPCO's remaining 58 percent share accounting for the remaining 313 MW. Ex. EGS-1 at Schedule FR-1.1 at 3; and Tr. Vol. XV at 3697-3698.[15]

GSU purchases coal for Big Cajun under a long-term contract with Triton Coal Company. The coal was shipped to the plant during the reconciliation period from Kerr-McGee's mines in Wyoming by rail transportation to St. Louis, Missouri, and then by barge on the Mississippi River

15. The Big Cajun power plant is actually a set of three coal-fired generating units, each of which is rated at a generating capacity of 540 MW. The total capacity of the Big Cajun power plant is 1620 MW. CEPCO owns Units 1 and 2 and operates all three Units. GSU's 42 percent share accounts for only about 14 percent of the total rated capacity of the Big Cajun power plant. Ex. EGS-1 at Schedule FR-1.1 at 3.

pursuant to an agreement with the Burlington Northern Railroad and American Continental Terminals, Inc. Ex. GC-12 at 9.

a. GSU's Calculation of Displaced Power Costs for Big Cajun II, Unit 3.

In late October 1994, CEPCO advised GSU that CEPCO had expended all available funds for operating its 30 percent share of the River Bend Nuclear Station (River Bend) and that it would therefore not make any further payment to GSU in 1994 for River Bend's operation and maintenance or capital expenses. Consequently, GSU ceased providing all power to CEPCO from River Bend and informed CEPCO that it would: (1) credit GSU's share of the expenses attributable to Big Cajun II, Unit 3, against amounts CEPCO owed to GSU for River Bend; and (2) seek to market CEPCO's share of the power from River Bend and apply the proceeds from that power against amounts CEPCO owed to GSU. Ex. EGS-16 at 10. When GSU informed CEPCO that it would withhold its payments for Big Cajun II, Unit 3, GSU expected that CEPCO would respond by refusing to provide GSU its share of electric power from Big Cajun II, Unit 3. CEPCO reacted as GSU had expected, and from November 2 through December 19, 1994,[16] CEPCO refused to provide GSU its share of power from Big Cajun II, Unit 3. Tr. Vol. XV at 3698.

Because CEPCO withheld GSU's share of the power from Big Cajun II, Unit 3, during the displacement period, GSU was forced to replace the energy which would have been generated by Big Cajun II, Unit 3, with more expensive energy, specifically with purchased power and increased generation from other EOC generating units ("Replacement Power"). However, instead of including the cost of the replacement power in its reconcilable costs, GSU made a policy decision to compute reconcilable costs for the displacement period as if Big Cajun II, Unit 3, had continued to supply

16. This time period is referred to as the "Displacement Period" both by GSU and in testimony provided by OPC expert witness Ms. Eileen Pitchford. The "Displacement Period" ended on December 19, 1994, when a Federal Court issued an injunction prohibiting CEPCO from denying GSU its share of energy from Big Cajun II, Unit 3, and requiring GSU to make payments into the registry of the Court for its portion of the expenses for Big Cajun II. Ex. OPC-21A at EP-3.

energy to GSU and as if GSU had not had to purchase the more expensive replacement power. Ex. OPC-21 at 10. GSU referred to this as a "Pseudo-Burn" and made a "Displaced Cost Adjustment" calculation to account for the difference.[17] GSU's intent was to keep its ratepayers "whole," in light of the litigious nature of the dispute and the fact that certain Big Cajun II costs were already included in its base rates. Ex. OPC-21A at EP 3.

b. <u>OPC's Recommended Disallowance of Coal Expenses for Big Cajun II</u>.

While OPC agreed with GSU's decision to try to keep its ratepayers whole by making the displaced cost adjustment, OPC did not agree that GSU calculated the displaced cost adjustment correctly. OPC's position is that GSU failed to correctly calculate the adjustment by underestimating the cost of replacement power and overestimating what it would have cost to generate the withheld power from Big Cajun II, Unit 3 during the displacement period. OPC In. Brief at 7. GSU overestimated what it would have cost to generate the withheld power from Big Cajun II, Unit 3, in several ways.

i. GSU's September 1994 Coal Cost Calculation.

OPC witness Ms. Eileen Pitchford recommended a disallowance for GSU's incorrect September 1994 calculation of coal costs for Big Cajun II, Unit 3, of $226,583 on a total company basis, or $90,653 on a Texas retail basis. Ex. OPC 21A at EP-1; and OPC Reply Brief at 1. In his rebuttal testimony, GSU witness Mr. J. David Wright agreed with Ms. Pitchford's recommended adjustment for September 1994 in its entirety. Ex. EGS-70A at 3. Therefore, the September 1994 disallowance is essentially no longer contested and this adjustment should be made by the Commission to correct the error.

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17. In other words, the "Displaced Cost Adjustment" GSU made represents the difference between the more expensive replacement power and an estimate of what the power from Big Cajun II, Unit 3, would have cost its ratepayers if it had been operated during the displacement period. OPC In. Brief at 6-7.

ii. GSU's October 1994 Displaced Cost Calculation.

OPC argues that GSU made several errors and unreasonable assumptions in calculating the pseudo-burn. The most serious of these errors, according to OPC, was the assumption that even though GSU increased the load on the Big Cajun II generating units by 227 MW, the average monthly heat rate[18] would have remained the same during the displacement period as it would have without GSU's 227 MW of load. In other words, according to OPC, GSU assumed that the unit was less efficient than it would have been with GSU's 227 MW load. According to OPC, even at the highest level of output used in GSU's test, the Nelson 6 base-load coal-fired generating unit had a lower incremental heat rate than its average heat rate. Ex. OPC 21A at EP-4. And GSU failed to carry its burden of proof to show that there was any reasons to expect that CEPCO would have backed down the load on Big Cajun II, Unit 3 during the displacement period.

Further, OPC argues that GSU made a second series of errors in calculating the pseudo-burn by including prior- month true-ups for the wrong months in its calculation of reconcilable coal costs. For example, in its calculation of the pseudo-burn for November 1994, GSU calculated the booked cost of coal as $454,514 and the costs of rail and barge transportation as $1,382,096 and $859,382, respectively. Ex. OPC 21A at EP-4; and Tr. Vol. XVI at 3841-3842. In making this calculation, OPC argues that GSU overstated or increased the cost of coal by $41,131, the cost of rail transportation by $2,712, and the cost of barge transportation by $38,012. These true-up adjustments applied to October 1994 coal purchases and had nothing to do with GSU's November coal costs. The correct true-up for November was recorded in December 1994 and resulted in a *reduction* of coal costs by $33,593, for a total of $74,724 ($41,131 plus 33,593). GSU's computation of the pseudo-burn overpriced GSU's reconcilable coal costs for November 1994 by a total of $347,888 due to GSU's improper application of prior-month true-ups alone. Ex. OPC-21A at EP-4.

18. A generating unit's heat rate is a measure of the unit's efficiency. Generating units are designed to achieve their lowest heat rates (i.e., highest efficiencies) at or near full load. As the load on a generating unit increases, the heat rate improves so that incrementally, it takes less Btu's to generate the next or incremental kWh of electricity, and therefore, the incremental heat rate is going to rise as the average heat rate is lowering with load. Ex. EGS-18 at 5-6; and Tr. Vol. XV at 3778.

OPC argues that GSU made a third error in computing the pseudo-burn by relying on incorrect estimates of the amount of coal that would have been burned at Big Cajun II, Unit 3, during the displacement period. OPC In. Brief at 12. OPC argues that GSU had to rely on CEPCO's estimates of the coal in its stockpiles from September 1994 through March 1995, and that coal stockpile surveys performed during that time indicated that CEPCO had more coal in its stockpile than was recorded on its books. This indicates that arguably, Big Cajun II, Unit 3, was operating more efficiently and at a lower heat rate than was reported by CEPCO during the displacement period. Thus, GSU's estimates of the coal burned and of the heat rate of the unit were too high, resulting in an overestimation of the cost of the power from Big Cajun II, Unit 3, had CEPCO provided GSU its share.

OPC witness Ms. Eileen Pitchford testified that rather than make incorrect assumptions about the amounts of coal in CEPCO's stockpile or the loads experienced by Big Cajun II, Unit 3, and thus its units' efficiencies, her recommendation would be to calculate the pseudo-burn using GSU's own dispatchers' cost to decide whether to schedule generation from Big Cajun II, Unit 3. Ms. Pitchford's estimate of the pseudo-burn coal costs was based on the \$14.85/MWh cost GSU used in its PROMOD computer model runs to estimate the merger-related fuel savings during the reconciliation period. Ex. OPC-21 at 15-19. Ms. Pitchford reasoned that because no one really knows what the heat rate at Big Cajun II, Unit 3 would have been during the displacement period, the best cost estimate available is the price GSU itself relied upon in deciding whether or not to schedule power from that unit. Tr. Vol. XV at 3741. OPC argues that its methodology for calculating the pseudo-burn is conservative because it is not affected by the improper prior-month true-ups and underestimated coal inventories, and should be adopted as the only reasonable estimate of the correct calculation of the pseudo-burn and displaced cost adjustment. OPC In. Brief at 15-16.

GSU's rebuttal, as reflected in Mr. Roy Giangrosso's testimony, is that the heat rate for Big Cajun II, Unit 3, is affected by factors other than GSU's 227 MW load and that Ms. Pitchford's dispatch price is low in comparison to GSU's dispatch price in previous months. Ex. EGS-59 at 5-11. Assuming these arguments to be true however, would still require the use of GSU's methodology to calculate the cost of replacement power.

c. ALJ's Recommendation Regarding Coal and Replacement Power Costs for Big Cajun II, Unit 3.

i. What is the Appropriate Methodology for Calculating the "Pseudo-Burn" or Displaced Power Costs for Big Cajun II, Unit 3, and how does it affect GSU's Reconcilable Coal Costs for Big Cajun II, Unit 3?

The ALJ agrees with OPC witness Ms. Eileen Pitchford that GSU's methodology for calculating the "pseudo-burn" or the displaced power costs for Big Cajun II, Unit 3, had CEPCO been willing to provide GSU its 227 MW share of power during the displacement period, was fraught with errors and questionable assumptions. Ms. Pitchford testified that it was impossible to make an accurate prediction or assumption of the tons of coal that would have been burned during the displacement period because the necessary data was not available. Tr. Vol. XV at 3720. The ALJ finds that as a result of relying on the questionable coal data provided by CEPCO, which data fails to take into account the effect of prior-month true-ups and of the 50,000 ton coal inventory adjustment made by CEPCO, GSU based its calculation of the pseudo-burn and displaced power cost on unsound data. The ALJ finds that it was therefore simply not possible for GSU to accurately predict what the heat rate and relative unit efficiency of Big Cajun II, Unit 3, would have been in order to accurately calculate the pseudo-burn or displaced power cost. Tr. Vol. XV at 3726; 3788-3789.

OPC witness Pitchford testified that because it was not possible to accurately predict what the heat rate at Big Cajun II, Unit 3, would have been during the displacement period, the best cost estimate available was the price GSU itself relied upon in deciding whether or not to schedule power from Big Cajun II, Unit 3. Tr. Vol. XV at 3741; and Tr. Vol. III at 664. Ms. Pitchford recommended calculating the displaced power cost utilizing an approximate cost of $15/MWh, which is the cost GSU's own dispatchers use in determining whether to schedule power from Big Cajun II, Unit 3. Ex. OPC-21 at 15-19. This cost is also very close to the $14.85/MWh GSU used in its PROMOD computer runs to estimate merger-related fuel savings during the reconciliation period. GSU witness Mr. Roy Giangrosso testified that these two cost estimates are essentially the same. Tr. Vol. VII at 1769-1770.

The ALJ agrees with Ms. Pitchford that if the cost of generation at Big Cajun II, Unit 3, for the reconciliation period is estimated to be $14.85/MWh, and if as GSU represented, 95.27 percent of that cost is reconcilable or eligible cost, then the reconcilable cost of the displaced energy at Big Cajun II, Unit 3, may reasonably be estimated to be $14.15/MWh, (or 95.27 percent of $14.85/MWh). Ex. OPC-21 at 18. Therefore, the ALJ finds that $14.15/MWh is the cost which should be used to compute the displaced energy adjustment for Big Cajun II, Unit 3, during the reconciliation period.

The ALJ finds reasonable Ms. Pitchford's methodology for the calculation of the displaced power costs for Big Cajun II, Unit 3, by multiplying the 255,300 MWh of displaced energy at Big Cajun II, Unit 3, for the displacement period, times $14.15/MWh to estimate resulting reconcilable costs of generation at Big Cajun II, Unit 3, for the reconciliation period. Those costs total $3,612,495, which is $704,608 less than the $4,317,103 which GSU charged to reconcilable fuel costs. Ex. OPC-21 at 19. The ALJ agrees with Ms. Pitchford that the use of this methodology would also eliminate the problem of having tons of coal in inventory which GSU had already burned for purposes of accounting, but which were actually still "on the ground." The ALJ recommends that the Commission adopt OPC's and Ms. Pitchford's methodology.

As for the September 1994 calculation error, the ALJ agrees with Ms. Pitchford that had GSU calculated reconcilable coal costs for September 1994 utilizing the correct tons of coal actually burned, the total reconcilable coal costs for that month would have been $2,368,985 for coal stock purchases and transportation, instead of the $2,594,568 figure which GSU sponsored. Ex. OPC-21 at 5. The ALJ finds that the difference between these two totals is approximately $225,583 on a total company basis, or $90,653 with interest on a Texas retail basis representing OPC's recommended disallowance for the error to account for inflated coal burn figures relied upon by GSU. The ALJ finds that in its report for September 1994, CEPCO reported that GSU's coal burn was actually 96,472 tons. Ex. OPC-21 at 4. The ALJ finds that when GSU computed the costs of coal removed from inventory for the month of September 1994, it erroneously based its computation on 105,428 tons, or 8,956 tons more than were actually burned. Ex. OPC-21 at 4; and EP-2 (declassified).

The ALJ finds that Ms. Pitchford's methodology appropriately results in a reduction in coal costs of $704,608 on a GSU total systemwide basis, or $226,447 with interest on a Texas retail basis, to compensate for GSU's errors in calculating the costs of generating the displaced energy at Big Cajun II, Unit 3, from November 2 through December 19, 1994. The ALJ finds in accordance with Ms. Pitchford's amended methodology that the a reduction of $90,653 on a Texas retail basis is appropriate to correct for the error in computing Big Cajun II, Unit 3, coal costs for the month of September 1994. Ex. OPC-21 at 3. The ALJ finds that the total recommended disallowance for GSU's Texas system only, with interest, is $317,100, as calculated by Ms. Pitchford in Ex. OPC-21A at EP-1 (declassified); and OPC Reply Brief at 1 and Attachments. Accordingly, the ALJ recommends that the Commission disallow $317,100 in GSU's Texas jurisdictional coal costs for the reconciliation period.

3. ALJ's Recommendation Regarding GSU's Long-Term Coal Purchases for Big Cajun.

GSU's portion of the long-term coal consumed at Big Cajun during the reconciliation period was 1,599,232 tons (or 25,943,427 MMBtu), representing total reconcilable coal expenses of $33,707,201. Ex. EGS-1 at FR-16.1; and Ex. GC-12 at 25. The coal supply for Big Cajun was purchased by CEPCO in conjunction with the Western Fuels Association (WFA). The ALJ finds as Commission Staff witness Mr. T. Brian Almon concluded that GSU's long-term coal expenses of $33,707,201 for Big Cajun during the reconciliation period were reasonable. As Mr. Almon recommended, the ALJ recommends that GSU's portion of the Big Cajun long-term coal expenses of $33,707,201 be reconciled, subject to the disallowance recommended by OPC. Ex. GC-12 at 26.

4. ALJ's Recommendation Regarding Coal Inventory Accounting Issue: What is the effect on Gulf States and its ratepayers, if any, of GSU's change in coal inventory accounting methodology from last in, first out (LIFO) to average cost in the absence of a corresponding rate base adjustment to fuel inventory in a general rate case? (Preliminary Order Issue No. 5)

On January 1, 1995, GSU changed its coal inventory accounting methodology from last in, first out (LIFO) to the average cost method. GSU changed from LIFO to an average cost accounting method to be consistent with the Entergy system of valuing inventory. GSU uses the average cost method for valuing fuel oil and the modified average cost method for valuing the natural gas inventory at the Spindletop natural gas storage facility. Ex. EGS-16 at 11; and Ex. GC-12 at 16.

GSU witness Mr. J. David Wright filed supplemental direct testimony that the value of GSU's coal inventory using the average cost method decreased by approximately $996,109 during the reconciliation period. According to Mr. Wright, the corresponding decrease in GSU's revenue requirement would be a net reduction in Texas retail base rates of $56,787. Mr. Wright concluded that neither GSU nor its ratepayers were significantly harmed by the change in coal inventory accounting methodology during the reconciliation period in light of GSU's total Texas retail revenue requirement of $650,638,062 as ordered in GSU's last base rate case in Docket No. 12852. Ex. EGS-17 at 2-3. This coal inventory accounting methodology change will be fully reflected in GSU's next general rate case.

Commission Staff witness Mr. T. Brian Almon testified that he had performed an independent evaluation of the effect of the coal cost accounting methodology change on GSU and its ratepayers. Mr. Almon testified that he compared the potential difference between what the ratepayers would have been charged for coal under both inventory methods for the reconciliation period and concluded that the coal cost for Nelson Station was $1,380,729 less than it would have been if GSU had continued to use the LIFO method. Mr. Almon found that, similarly, the coal costs for Big Cajun with the average cost method were $448,901 less than they would have been under the LIFO method. Thus, Mr. Almon concluded that the total cost of fuel during the reconciliation period was actually lower because of the change from the LIFO to the average cost method. Ex. GC-12 at 17.

The change from LIFO to the average cost method resulted in fuel savings because the prices GSU paid for coal purchased during the first six months of 1995 were higher than the average price of all of the coal in inventory. Under the LIFO method, the coal from GSU's inventory would reflect the current market price. In contrast, under the average cost accounting method, the cost of the less expensive coal purchased by GSU in previous years decreased the overall average cost of coal burned at GSU's power plants. Ex. GC-12 at 17. Mr. Almon's conclusion was that the change from the LIFO accounting method to the average cost method during the reconciliation period was reasonable and prudent and that the change did not have a significant impact on the ratepayers. Ex. GC-12 at 18.

The ALJ agrees with Commission Staff witness Almon and GSU that GSU's change from LIFO to the average cost coal accounting methodology during the reconciliation period was reasonable and prudent because it resulted in lower coal and fuel costs than would have been the case under the LIFO method. The ALJ finds that the change resulted in fuel savings because the prices GSU paid for coal purchased during the first six months of 1995 were higher than the average price of all of the coal in inventory, and under the LIFO method, the coal from GSU's inventory would reflect the current or higher market price. In contrast, under the average cost accounting method, the cost of the less expensive coal purchased by GSU in previous years decreased the overall average cost of coal burned at GSU's power plants. Ex. GC-12 at 17. The ALJ believes the change tended to benefit, rather than harm GSU's ratepayers.

Further, the ALJ finds that the value of GSU's coal inventory decreased by approximately $996,109, with a corresponding decrease in the revenue requirement resulting in a net reduction of

Texas retail base rates of $56,787. Ex. EGS-17 at 2 and JDW-1. In light of GSU's total Texas retail revenue requirement of approximately $650,638,062 as ordered in Docket No. 12852, GSU's last base rate case, the ALJ finds that a net reduction of $56,787 in retail base rates is insignificant. Tr. Vol. X at 2478. Therefore, the ALJ finds that neither GSU nor its ratepayers were significantly impacted by the change from LIFO to average cost coal inventory accounting methodology during the reconciliation period in the absence of a corresponding base rate adjustment to fuel inventory and recommends that the Commission so find.

The ALJ further agrees with GSU witness Mr. Wright that inventory balances ordinarily change over time and that the amount reflected in rates would normally vary from actual book inventory amounts. These differences are normal in the ratemaking process and would result in minimal differences in value. Tr. Vol. X at 2478-2479; and Ex. EGS-17 at JDW-1. Therefore, the ALJ recommends that the Commission find that neither the ratepayers nor GSU were significantly impacted or harmed by GSU's change from LIFO to the average cost coal accounting methodology during the reconciliation period and that the change was reasonable and prudent.

C. Fuel Oil Expenses

During the reconciliation period, GSU burned approximately 221,192 barrels of fuel oil, or the equivalent of 1,396,899 MMBtu of energy. Ex. EGS-1 at Schedule FR-16.1; and Ex. GC-12 at 29. GSU burns small amounts of No. 2 fuel oil at its Sabine Station, Nelson 6, and Big Cajun II, Unit 3, power plants for start-up and flame stabilization. Additionally, GSU maintains contingency supplies of No. 6 fuel oil in inventory at its Sabine, Willow Glen, and Nelson Stations in the event of gas curtailments during severe cold weather. GSU purchased its fuel oil during the reconciliation period by soliciting bids from an approved qualified bidder's list. It accepted deliveries made by barge, except at its Lewis Creek Power Plant, which can receive fuel oil only by truck. Ex. GC-12 at 29.

Commission Staff witness Mr. T. Brian Almon concluded that GSU's fuel oil purchases during the reconciliation period were reasonable and necessary and the ALJ agrees. No party contested this issue and the Commission Staff was the only party to analyze GSU's fuel oil purchases during the reconciliation period. The ALJ finds that GSU's reasonable and necessary fuel oil expenses during the reconciliation period were $4,028,017, as recommended by Staff witness Almon. GC-12 at 8. The ALJ recommends that the Commission find that GSU's reasonable and necessary fuel oil expense during the reconciliation period was $4,028,017, as recommended by Commission Staff.

X. River Bend Nuclear Station Fuel and Outages

A. General Overview of River Bend Nuclear Station.

The River Bend Nuclear Station (RBNS) is a General Electric (GE)-designed Boiling Water Reactor (BWR) nuclear power plant located near St. Francisville, Louisiana, which is approximately 24 miles north of Baton Rouge, Louisiana. RBNS is jointly owned by GSU (70 percent) and CEPCO (30 percent), and is operated by Entergy Operations, Inc., since the merger between GSU and Entergy. Ex. GC-11 at 2. RBNS achieved commercial operation on June 16, 1986, with its reactor rated at a capacity 2,984 MWh and its turbine generator rated at 936 MWe. Ex. GC-11 at GWD-3.

Although prior to December 1994 RBNS' performance was poor based on a comparison of its heat rate, capacity factor, and forced outage rates with other U.S. BWRs, Entergy's plan for RBNS resulted in substantial improvement during the reconciliation period. RBNS' performance was comparatively poor during the reconciliation period due to an extended forced outage (FO-94-02) which started on September 8, 1994, and lasted approximately 42.7 days. Ex. GC-11 at 6.

GSU initially operated RBNS on a "stand-alone" basis. After the merger with Entergy, Entergy decided to implement performance improvement plans to bring RBNS' performance up to the level of operating efficiency of Entergy's other nuclear plants. The plans were designed to bring

RBNS to a level of excellence that would place it among the best performing nuclear plants in the country. The plans focused primarily on improving regulatory performance with the Nuclear Regulatory Commission (NRC), upgrading the material condition of the plant, assessing and evaluating the capabilities of the employees, as well as improving human performance, plant processes, and procedures.[19] Ex. EGS-13 at 6.

As a result of the performance improvement plans, substantial improvements were made in the material condition of the plant, in plant processes, and in plant personnel. Entergy was able to improve RBNS regulatory performance to achieve an overall Systematic Assessment of Licensee Performance (SALP) rating of 1.75.[20] The SALP score for RBNS from the previous period was a 2.5. RBNS' improvement has been characterized as the largest single improvement in the SALP score ever witnessed by the NRC. Ex. EGS-13 at 8.

B. River Bend Nuclear Fuel Costs and the Nuclear Fuel Cycle

The uranium (U3O8) utilized at RBNS during the reconciliation period was purchased primarily under long-term contracts that were entered into in the 1970's. During the 1970's, fuel-grade uranium was in short supply and prices were therefore high. The last of this expensive uranium was placed into the reactor during the refueling outage that occurred just prior to the reconciliation period in RBNS' fourth refueling outage (RF-4). This relatively expensive fuel will be fully used after

19. There were two performance improvement plans known as the "Near Term Performance Improvement Plan" or NTPIP and the "Long-Term Performance Improvement Plan" or LTPIP. The NTPIP defined the actions required to effect immediate performance improvements at RBNS, and its final actions were successfully completed during RBNS' Refueling Outage No. 5 (RF-5), which began in April 1994. The LTPIP defined activities for RBNS over a three-year period and focused on placing RBNS in the top quartile of nuclear plant performance nationwide. Ex. EGS-13 at 6.

20. SALP scores range from 1 to 3, with 1 being the best score. The score received by a plant is a composite of scores in four different areas. RBNS' latest SALP score of 1.75 is the composite of scores in the individual areas as follows: Plant Support-1; Plant Operations-2; Maintenance-2; and Engineering-2. The NRC has stated that RBNS' performance in the Plant Support category was superior, and its performance in the other three categories was characterized as good. Ex. EGS-13 at 6 and MBS-1.

the completion of fuel cycle 7, which ends with the start of RBNS's seventh refueling outage (RF-7), scheduled to occur some time in 1997. Ex. GC-11 at 7-8; and Ex. EGS-11 at 4.

GSU made purchases of RBNS uranium and all other fuel cycle services on behalf of CEPCO during the reconciliation period. The uranium contracts for RBNS nuclear fuel during the reconciliation period have previously been considered by the Commission in Docket No. 10894. Ex. EGS-11 at 4. Apart from GSU's legal arguments on the issues of *res judicata* and collateral estoppel, discussed below, in order to evaluate the reasonableness of fuel costs incurred by a utility for a nuclear power plant it is necessary to examine the nuclear fuel cycle.

1. The Nuclear Fuel Cycle.

The nuclear fuel cycle is the process by which uranium concentrates are acquired and transformed into nuclear fuel and utilized in the reactor core until they are removed and disposed of by the operator. Thus, the nuclear fuel cycle consists of a number of significantly different steps, each of which typically involves separate contracts and vendors. These steps include: (1) the procurement of uranium concentrates (U3O8); (2) the conversion of U3O8 to uranium hexaflouride (UF6); (3) the enrichment of UF6; (4) fuel assembly design and fabrication; (5) reactor operation; and (6) spent fuel storage and disposal. The costs of these steps, with the exception of reactor operation and spent fuel disposal, are accumulated as a total direct capitalized cost of nuclear fuel. The utility further capitalizes financing costs of the nuclear fuel incurred prior to insertion into the reactor core. During the reactor's operation, recoverable fuel costs include the amortization of the nuclear fuel, in-core financing costs, and spent fuel expense. Ex. EGS-11 at 2-3.

A typical fuel cycle for RBNS is approximately 18 months in duration, which includes a refueling outage period. Therefore, a typical fuel cycle consists of approximately 16 months of operation and approximately a two month refueling outage. To support an 18-month operating cycle, the reactor requires approximately 650,000 pounds of uranium. This amount represents about one-third of all of the fuel in the reactor. Each reload of fuel typically remains in the reactor for three cycles. Therefore, the reloading of the reactor is staggered so that approximately one-third of the fuel is replaced each cycle. Ex. EGS-11 at 4.

2. The History of RBNS Nuclear Fuel Relevant to Fuel Costs.

The uranium purchased by GSU pursuant to contracts entered into in the mid-1970s was used in the reactor core at RBNS from the time it achieved commercial operation until the present. The 1970s uranium has now all been loaded into the reactor and will be completely used over the next two refueling cycles, refueling cycles 6 and 7. Ex. EGS-11 at 6.

Additionally, in 1990, a time when uranium prices were low, GSU purchased a significant quantity of uranium in the spot market to complete the uranium requirements for RBNS refueling outage 4 (RF-4) in April 1992. By the end of 1990, GSU had signed two additional separate contracts to meet uranium requirements for RBNS into the late 1990s. The suppliers were Uranerz Exploration and Mining (Uranerz) and RTZ Mineral Services (RTZ). Ex. EGS-11 at 6. These contracts were awarded to Uranerz and RTZ after solicitation of and receipt of numerous bids. The reasonableness of these purchases was not contested.

The enrichment services were not bid because, at the time, all U.S. suppliers had to contract with the U.S. government for these services. Nevertheless, GSU achieved the prevailing market prices for its later uranium purchases and conversion services through the operation of GSU's competitive bidding process. GSU witness Mr. Frank B. Rives testified that, in his opinion, GSU's uranium, conversion, enrichment, and fabrication contracts were reasonable and consistent with the purchasing practices of other nuclear facilities at the time, both in price and contract terms. Ex. EGS-11 at 7.

3. Cities' Recommended Disallowance of RBNS Nuclear Fuel Costs.

The Cities adamantly contested the reasonableness of GSU's nuclear fuel costs during the reconciliation period. Cities' witness Mr. Richard Hubbard testified that in his opinion, overall RBNS nuclear fuel costs in mills/KWh (equivalent to dollars/MWh), in the period prior to and during the reconciliation period, are nearly the highest or most expensive of any nuclear plant in the U.S. Mr. Hubbard concluded that GSU's production fuel costs in mills/KWh for the reconciliation period for its 70 percent share of RBNS were still higher than the overall production costs for the plant.

And Mr. Hubbard concluded that RBNS fuel costs in mills/KWh were significantly higher than the production fuel costs for any of Entergy's other nuclear plants or for the other nuclear plants in Texas. Mr. Hubbard's testimony reveals his dissatisfaction with GSU's failure, in his opinion, to adequately quantify the reasons for the nuclear fuel costs at RBNS. Ex. Cities-48 at 17-29. Mr. Hubbard concluded that GSU had failed to demonstrate that its nuclear fuel costs of $66.8 million expended for RBNS during the reconciliation period were reasonable and necessary and found that GSU's avoidable nuclear fuel cost for its share of RBNS was $27,686,978. Ex. Cities-48 at 89. He recommended that $27,686,978 be disallowed.

Significantly, Cities' witness Mr. Hubbard based his disallowance on the fuel production costs for RBNS which he found to be in excess of the "industry average," utilizing nuclear fuel production costs for the 3-year period from 1992 to 1994. He testified that he selected this time period to "normalize" refueling cycles and to emphasize sustained performance. Ex. Cities-48 at 88. In the three year period from 1992 to 1994, Mr. Hubbard found the U.S. average nuclear fuel production cost was 6.31 mills/KWh, despite the fact that a significant portion of the nuclear fuel remaining in-core at RBNS during the reconciliation period was purchased when prices were higher in the 1970s.

4. **ALJ's Recommendation Regarding GSU's Reconcilable Nuclear Fuel Costs for RBNS.**

a. Whether GSU's Nuclear Fuel Costs for RBNS during the Reconciliation Period are Subject to Review for Reasonableness after the Commission's findings in Docket No. 10894?

GSU argues that the judgment rendered in Docket No. 10894, a fuel reconciliation case to which OPC, TIEC, North Star Steel, the Cities served by GSU and General Counsel were parties, is an absolute bar to retrial of claims concerning the reasonableness of the nuclear fuel costs incurred pursuant to the 1970's contracts, given the identity of parties, issues and subject matter. GSU argues that the application of the doctrine of *res judicata* to this case is entirely consistent with the Texas Supreme Court's expressed awareness of the "usefulness of *res judicata* in administrative proceedings," and its "strong preference that 'continued litigation of issues or piecemeal litigation should be discouraged' in state regulatory agencies."[21]

The Commission has determined that only the administration of contracts can be reviewed in proceedings subsequent to the period a contract is negotiated and executed.[22] The ALJ agrees with GSU that the Commission's decision in Docket No. 10894 already determined the issue of the reasonableness of GSU's nuclear fuel costs under the contracts that supplied the uranium in the core-in-service at RBNS during the reconciliation period. The Commission made the following findings:

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21. *Coalition of Cities v. Public Utility Comm'n*, 798 S.W. 2d 560, 563 (Tex. 1990); *and Application of Southwestern Electric Power Company to Reconcile Fuel Costs*, Docket No. 12855, 20 P.U.C. Bull. 843, at 864-65 ("[O]nce the Commission has reviewed the prudence of the original prices, terms, and conditions of a fuel contract in a fuel reconciliation proceeding, *res judicata* precludes the reconsideration of such in a subsequent proceeding"); *Application of Gulf States Utilities Company for a Final Reconciliation of Fuel Costs*, Docket No. 10894, 19 P.U.C. BULL. 1401 (July 6, 1993) (Findings of Fact Nos. 136, 223, and 359).

22. *Petition of General Counsel for a Fuel Reconciliation for Southwestern Public Service Company*, Docket No. 9030, 17 P.U.C. Bull. 395, (June 3, 1991) (Consistent with the doctrines of *res judicata* and collateral estoppel, the Commission determined that under the fuel rule only the administration of previously considered fuel contracts and not the prudence of the underlying terms could be subject to review).

136. For the reconciliation period, GSU is requesting that $158,221,970 in nuclear fuel costs be treated as reconcilable. GSU's reconcilable nuclear fuel costs include nuclear amortization, spent fuel and interest expense.

223. Nuclear fuel costs are broken into three major components: (1) the amortization of the nuclear fuel actually consumed; (2) the DOE spent fuel fee which is a flat fee per MWh of generation; and (3) the interest payments on the remaining unused nuclear fuel.

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

The issue was fully and fairly litigated in that proceeding and no party contended that it was deprived of the opportunity to introduce evidence or testimony on those issues. Moreover, the identity of the parties is the same, as is the identity of the issue attempted to be raised by Cities in this proceeding. Therefore, under the doctrine of *res judicata*, the Cities are precluded from raising this issue again.

Alternatively, and to the extent the commission believes GSU's nuclear fuel costs are subject to review for other than contract administration, the following discussion addresses the reasonableness of the nuclear fuel costs.

b. Whether GSU's Nuclear Fuel Costs for RBNS during the Reconciliation Period are Reasonable and Necessary?

GSU argues alternatively that, as a factual matter, although its nuclear fuel costs were higher than those of other U.S. nuclear power plants during the reconciliation period, those costs were the result of prudent long-term contractual commitments entered into in the 1970s when prices were high; therefore, it made prudent inventory management decisions. GSU witness Mr. Frank B. Rives, Director of Nuclear Fuels of Entergy Operations, Inc., testified that the cost associated with the uranium purchased under long-term contracts in the 1970's and utilized during the reconciliation period was the reason for the relatively high costs of nuclear fuel incurred by GSU for RBNS. Ex. EGS-65 (Rives Reb.) at 16-20.

Commission Staff witness Mr. Glenn W. Dishong agreed with Mr. Rives. Ex. GC-11 at 7; and Tr. Vol. XVI at 3945. In Mr. Dishong's opinion, the cost of nuclear fuel at RBNS remains high following the addition of relatively inexpensive fuel in RF-5 because the composition of the reactor core continues to include expensive fuel from previous fuel cycles. Ex. GC-11 at 8. He concluded that the fuel costs for RBNS during the reconciliation period were reasonable.

The ALJ finds that the reason GSU's nuclear fuel costs for RBNS during the reconciliation period were relatively higher than the national average for other nuclear plants is because the composition of the reactor core, or "core-in-service" during the reconciliation period still contained a substantial amount of expensive uranium which was purchased by GSU between February 1976 and April 1984, when market prices averaged $40/lb. of uranium. Ex. GC-11 at 8; and Schedule GWD-8. Schedule GWD-8 of Mr. Dishong's direct testimony reveals the reality of the 18 month nuclear fuel cycle.

Although during refueling outage five (RF-5), GSU placed less expensive uranium into the core-in-service, during the reconciliation period RBNS continued to contain expensive uranium from Reload 3 and approximately 75 percent expensive uranium from Reload 4. Ex. GC-11 at Schedule GWD-8. On a total percentage basis, this means that from April 1994 through January 1996, the core in service at RBNS still contained approximately 52.5 percent of the expensive fuel, causing the relatively high nuclear fuel costs at RBNS during the reconciliation period.

The ALJ rejects Cities' attempt to apply an inappropriate standard to judge the reasonableness of GSU's nuclear fuel costs. Mr. Hubbard based his recommended disallowance on the average prices for uranium that did not exist at the time GSU purchased a substantial portion of the uranium remaining in the core-in-service at RBNS during the reconciliation period. Mr. Hubbard's proposed disallowance of RBNS nuclear fuel costs was based on average prices from 1992 to 1994 and therefore his standard is inappropriate because it is based on hindsight. Ex. Cities-48 at 88.

The reality of the 18 month nuclear fuel cycle is the fact that nuclear fuel resides in the core-in-service for three full cycles, demonstrating that the majority or 52.5 percent of the core-in-service during the reconciliation period contained expensive uranium fuel purchased by GSU between February 1976 and April 1984. Ex. GC-11 at Schedule GWD-8. Cities' analysis failed to realize or adequately account for the reality of the nuclear fuel cycle and the makeup of the core-in-service. Therefore, the ALJ finds that the Cities' disallowance of nuclear fuel costs should be rejected and recommends that the Commission find that GSU's entire $66,832,690 in nuclear fuel costs during the reconciliation period is reasonable and necessary and subject to reconciliation without any disallowances.

c. Potential Refund of Decontamination & Decommissioning Fees.

Cities' witness Mr. Hubbard raised an interesting issue regarding the potential refund due to GSU from the U.S. Department of Energy (DOE) of Decontamination and Decommissioning (D&D) costs for RBNS and whether such costs should be included in GSU's reconcilable fuel costs. According to Mr. Hubbard, Title XI of the National Energy Policy Act of 1992 established the D&D fund with the U.S. Treasury and provided for annual deposits of $150,000,000 via a special assessment from domestic utilities. The assessment is a fixed yearly fee that is not based on fuel burn up. It is an assessment similar to taxes that should arguably be included in base rates. Ex. Cities-48 at 30.

More significantly, on June 22, 1995, a federal court struck down the DOE's attempt to retroactively collect an annual assessment from nuclear plant owners for its Uranium Enrichment

D&D fund.[23] The same costs are included in GSU's application in this case. The case between Yankee Atomic and the DOE has been appealed by the DOE and is still pending. The remaining potentially affected utilities are monitoring this litigation closely. Although neither GSU nor Entergy has sought or received a refund from DOE of its share of D&D fees, GSU made its last payment "under protest with full reservation of all rights to challenge the validity of the assessment and to seek a refund of the entire amount of the payment, plus interest as allowed by law." Ex. Cities-48 at 31.

Because GSU has not yet received any refund of D&D fees, Cities' witness Mr. Hubbard did not recommend a disallowance of the $1.3 million in D&D fees for RBNS included in GSU's application in this proceeding. However, he did recommend that, in the future, the Commission may wish to order GSU to cease any further payments to the DOE in light of the federal court's findings that such payments constituted "unlawful exaction." The ALJ ordered GSU to file a written status report including the refund issue in its next fuel reconciliation and rate proceeding. It is the ALJ's recommendation that the Commission order GSU to include the potential $1.3 million refund so the Commission may consider the amount of the refund in the future proceeding.

C. Outages at River Bend Nuclear Station

1. The Duration of Refueling Outage 5 (RF-5); Outage No. 94-02.

Refueling outage five (RF-5) at RBNS began on April 15, 1994, and ended on July 6, 1994. This outage was originally planned to take 53 days, but ultimately was extended to 82 days. A major goal established for the outage included completing modifications to improve the material condition of the plant and to reduce the likelihood of forced outages in the future. Ex. EGS-13 at 10; and Ex. GC-11 at 9. The major activities planned for RF-5 were (1) replacement of approximately one-third of the used fuel assemblies; (2) motor-operated valve testing; (3) main turbine rotor

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23. *Yankee Atomic Electric Co. v U.S.*, 33 Fed.Cl. 580, 4 (June 22, 1995).

replacement; (4) Residual Heat Removal (RHR) system repairs; (5) diesel generator maintenance; and (6) other modifications to existing plant systems. Ex. GC-11 at 9.

In general, the purpose of a refueling outage is to refuel the reactor by replacing approximately one-third of the nuclear fuel in the reactor core, to make repairs or modifications to the plant that cannot reasonably be made when the plant is operating, and to correct problems that are identified for the first time during the outage. From a management perspective, the length of an outage is projected by evaluating the tasks on the "critical path." The critical path for an outage is the series of the most lengthy tasks during an outage that cannot be performed simultaneously. The integrated nature of the work performed during a refueling outage is very complex and there is always parallel work being performed. Parallel work that would have become critical path if the actual critical path activity had not occurred is called the "near-critical path activity." Ex. EGS-13 at 10.

a. Cities' Recommended Disallowance and Analytical Methodology.

Cities' witness Mr. Richard Hubbard testified that RF-5 could reasonably have been completed in 53 days, rather than the 82 days GSU spent. In Mr. Hubbard's opinion, RF-5 was extended to address long-standing equipment and management problems that preceded Entergy's management of RBNS in late 1993. Mr. Hubbard testified that problems at RBNS recurred due to GSU's deficient management before the merger. Accordingly, Mr. Hubbard concluded that the extension of RF-5 beyond the planned 53 day length of the outage represented an avoidable consequence that directly stemmed from GSU's management of RBNS prior to 1994. Due to the large back-log of long-standing problems at RBNS, Mr. Hubbard believed that Entergy was not able to freeze and complete all design modifications to be performed during the outage in advance. In summary, Mr. Hubbard concluded that the extension of RF-5 is an example of avoidable plant down time that resulted from the degraded condition of RBNS. Ex. Cities-48 at 60.

Cities' witness Mr. David Wheeler testified that RF-5 was extended approximately 695.5 hours due to 'unreasonable management.' Mr. Wheeler based his analysis in large part on an acceptance of Mr. Hubbard's analysis, which did not include an evaluation of the critical path activities undertaken during RF-5. The avoidable time associated with RF-5, according to Mr. Wheeler, included 553.8 hours in June 1994 and 141.7 hours in July 1994. In Mr. Wheeler's opinion, it is not reasonable to expect ratepayers to pay for replacement power costs for the additional 29 days (the difference between the 53 days planned and the 82 actual days of the outage) it took to correct the unreasonable accumulation of material deficiencies in the plant. Ex. Cities- 49 at 3-6. For the Cities' alleged 29 day avoidable outage time for RF-5, Mr. Hubbard quantified his recommended disallowance at $2,500,116 for June 1994 and $856,135 for July of 1994, for a total recommended disallowance of $3,356,251. Ex. Cities-48 at 92-93.

b. General Counsel's Recommendation Relating to RF-5.

Commission Staff witness Mr. Glenn W. Dishong testified that RF-5 at RBNS extended beyond the original 53-day planned duration primarily due to work performed on the Residual Heat Removal (RHR) system and containment airlock modifications. According to Mr. Dishong, the RHR work was planned for RF-5 because the 25 day anticipated length of the work exceeded plant technical specifications for out-of-service time during normal operations. The most significant element of the RHR work was the replacement of the two large motor-operated valves (MOVs: F024A and F024B). These valves had a history of poor performance and were being replaced by a new design, according to Mr. Dishong. Ex. GC-11 at 10.

In Mr. Dishong's opinion, the cause of the delay in the RHR work was the increased scope of the work, including boundary valve leakage, power line conditioner repairs, and MOV-F024B repairs following testing. A leaking isolation valve (E12*VF14B) caused five days of the extension. This valve provided the necessary safe working boundary to allow work to be performed on another valve. The failure and subsequent repair of another valve (E12*MOV24B) during testing caused an additional three days of delay. The failure of this valve was due entirely to a material defect that was not under the control of GSU management. Finally, Mr. Dishong found that an additional 5-day delay resulted from the repair of a power line conditioner that was not in the original scope of the work. Ex. GC-11A at 3 (errata). These findings essentially eliminated Mr. Dishong's initial recommended disallowance of the additional 23 days required for completion of this work. Ex. GC-11 and 11A at 3.

In contrast, the containment airlock[24] work was not prudently managed in part because it was never scheduled to be a critical path activity, according to Mr. Dishong. Performance of the airlock modifications should, therefore, not have impacted the length of the outage. Planning of the airlock modifications was not complete as of March 20, 1994, only 25 days prior to the outage. Because the airlock is heavily used for access to the reactor containment during an outage, the modification of this equipment should have been carefully planned to ensure compatibility with the activities inside the containment. Therefore, the containment airlock work unreasonably contributed approximately 12.94 days to the duration of RF-5, based on Mr. Dishong's analysis. Mr. Dishong's recommended disallowance of 12.94 days for failure to plan and implement the airlock work amounts to $1,830,569 in replacement nuclear fuel costs, assuming the cost of nuclear fuel is calculated at an average of $8.60 for the reconciliation period. Ex. GC-11A at 3; and General Counsel In. Brief at 43-44. GSU did not agree with Mr. Dishong's recommended disallowance.

GSU witness Mr. Michael Sellman testified on rebuttal that while it was true that the containment airlock work was not originally scheduled to affect the critical path, despite thorough preparation efforts, there were unanticipated problems that delayed the completion of the work. He testified that these problems were not problems which a reasonable utility operator would have been

24. The containment airlock is an entry to the portion of the plant that contains the reactor and its associated piping. This entry is a system of two doors in series and allows one door to be opened without disrupting the integrity of the containment, which is designed to contain radioactive material in the event of a reactor accident. These doors are typically very large with highly complicated electrical and mechanical components to ensure a tight fit and to prevent simultaneous opening. In March 1993, employees were trapped in the airlock due to airlock pressurization caused by the failure of a door seal. Ex. GC-11 at 11.

able to avoid and that GSU should not be deemed imprudent on account of them. Ex. EGS-67 at 19. These problems included: difficulty fitting parts to the airlock hardware; damage of the cables during the attempted fitting of parts; some of the parts would not work properly after they were installed; and there was necessary personnel traffic through the doors during the refueling outage, delaying some of the work. Ex. EGS-67 at 18. Although GSU attempted to do a thorough on-site design review of the airlock modifications in advance, the fact remains that none of the work was scheduled as critical path activity and the modifications should have been more carefully planned to ensure compatibility with the activities within the reactor containment during the refueling outage, since the airlock is heavily used for access to the containment during a refueling outage. Ex. GC-11 at 11.

c. **ALJ's Recommendation Regarding RF-5.**

i. Was the duration of GSU's River Bend refueling outage number five (RF-5) reasonable and was the outage prudently planned and managed? (Preliminary Order Issue No. 6)

The ALJ finds that the duration of GSU's River Bend refueling outage number five (RF-5) was reasonable to the extent of 69.06 days, and to that extent, the outage was prudently planned and managed. However, the ALJ recommends that the Commission find that 12.94 days of the extension of outage RF-5 was unreasonable due to the failure to adequately plan and manage the containment airlock work at RBNS during the reconciliation period. GSU did not plan the airlock work as a critical path activity and it should therefore not have extended RF-5. Therefore, the ALJ recommends the Commission find that the cost of the replacement power attributable to the 12.94-day extension of the outage is $1,830,569, based on the finding that the average cost of nuclear fuel at RBNS during the reconciliation period was $8.60/MWh. The ALJ recommends that the Commission disallow $1,830,569 in replacement power costs due imprudent airlock work during RF-5.

Cities' recommendation would have the Commission disallow 29 days of the time required to complete RF-5 at RBNS, without performing a task-specific analysis of the critical path activities for RF-5, on the basis that the outage was planned to take 53 days but actually took 82. The ALJ finds the Cities' proposed 29-day disallowance of replacement power costs to be inappropriate and arbitrary because it is not based upon a task-specific critical path analysis of the prudence of the activities undertaken during RF-5 or their contribution to the plant's improved performance, but rather, simply represents the difference between the originally planned outage duration and its actual duration.

Without reference to the specific tasks and an analysis of the outage based on critical path activities, the ALJ believes that it is next to impossible to decide whether or not a particular extension was the result of imprudent management or whether the extension was reasonable and prudent. Because of their faulty analysis, the Cities' witnesses were unable to explain how the 29-day extension of RF-5 was attributable to past management practices. Although Mr. Hubbard had testified in the past that the performance of a nuclear plant owner should be evaluated based on its specific decisions and actions, neither Mr. Hubbard nor Mr. Wheeler could identify any specific decision or action undertaken during RF-5 that was imprudent or the result of imprudence. Ex. EGS-67 (Sellman Reb.) at 12; and MBS-10 at 121-23; and MBS-8 at 381.

The ALJ believes that it is essential to evaluate critical path activities undertaken during a refueling outage in order to make an assessment of the reasonableness of the duration of a particular outage. By definition, critical path activities are ones that actually determine the eventual length of the outage. Tr. Vol. XVI at 3910. As Mr. Dishong explained, "[a]nything that isn't critical path or could not have become critical path has no bearing on the eventual length of the outage." Tr. Vol. XVI at 3911. Neither Mr. Wheeler nor Mr. Hubbard made task-specific assessments of the work that was done on the RHR system or on the airlock during RF-5. Cities' witnesses were unable to identify any acts or omissions that had been made in the past that might have avoided the need to undertake these projects during RF-5. Tr. Vol. XI at 2578; 2580-81. Mr. Hubbard explained that he made a "conscious decision not to review minutia," and therefore, did not concern himself with identifying which tasks undertaken during the refueling outage were on the critical path. Tr. Vol. XI at 2732-33.

The ALJ finds that Cities' recommendation is based on an unsound analysis because it is not based on a task-specific critical path analysis; therefore, the ALJ rejects Cities' witnesses' recommended disallowance for RF-5. In contrast to Cities' analysis, Mr. Dishong evaluated the prudence of individual critical path activities undertaken during RF-5 and prepared a chart displaying all critical path and near critical path activities performed during the refueling outage, and evaluated whether the time spent on each activity was reasonable. Tr. Vol. XVI at 3905-07. By evaluating each critical path activity, he was able to determine what the reasonable length of the outage should have been. Tr. Vol. XVI at 3909.

Based on his sound analysis and extensive experience, Staff witness Dishong recommended a disallowance of 12.94 days, finding that the prudent duration of the outage was 69.06 days. Tr. Vol. XVI at 3913. Mr. Dishong's analysis of the specific critical path activities performed during RF-5 highlights the fundamental flaw in the Cities' methodology. Therefore the ALJ finds more credible the Commission Staff's analysis and recommends that the Commission adopt General Counsel's recommended disallowance of 12.94 days for airlock modifications during RF-5 and disallow $1,830,569 in replacement power costs attributable to that period.

2. Forced Outage 94-01 (FO-94-01); Outage No. 94-03: Vessel Transmitter -Spurious Trip.

On September 8, 1994, RBNS experienced a process "noise spike" that was perceived by the reactor vessel water level transmitters as a high water level. The transmitters sent a "scram signal" to the reactor protection system logic, which shut down the plant. This automatic shutdown feature ensures that water will not enter the steam lines and eventually travel to the main turbine where the turbine blading could be damaged. Ex. EGS-13; and Ex. GC-11 at 14. The actual source of the initiating event or noise spike was never identified, but all four of the water level transmitters responded to the event. Ex. GC-11A at 4.

GSU also replaced a leaking fuel rod assembly during forced outage 94-03 and repaired eight segments of Control Rod Drive (CRD) piping, one of which was found to be leaking. Forced outage 94-03 lasted 42.7 days. Ex. EGS-13 at 12-13.

a. Rosemount Model 1153 Transmitter Damping.

In a BWR nuclear plant, the reactor vessel water level is determined by a comparison of the pressure of a known height of water to that of the water in the reactor vessel. This comparison of pressures is translated into a water level indication and monitored by the control system. During RF-5, GSU had replaced two of the four reactor vessel water level transmitters due to degradation of the originally-installed Rosemount Model 1152 Transmitters. Because the original Rosemount Model 1152s were no longer manufactured, GSU purchased two new Rosemount Model 1153s. Ex. GC-11 at 14.

Commission Staff witness Mr. Glenn Dishong testified that the Rosemount Model 1153 Transmitters were not used improperly in this application. He testified that GSU personnel had known that the failure of an old Model 1152 would require replacement with a Model 1153 and that GSU had prepared a modification request to complete the replacement as necessary. The modification request and recommendations by GE indicated a need for installation of a special "damping"[25] card to allow the Model 1153 to function like the Model 1152. Ex. GC-11A at 4.

25. "Damping" on a transmitter serves to filter out spurious signals that do not represent actual vessel water level conditions. Damping functions to screen out unimportant signals, such as a valve closing somewhere within the reactor piping system, causing a momentary change in pressure. Ex. EGS-13 at 14.

According to Mr. Dishong, in this particular case GSU personnel installed one of the new transmitters without the damping card and the other transmitter contained a damping card with incorrect settings. Ex. GC-11A at 4. Mr. Dishong agreed with GSU's argument that even with the proper damping cards installed in both the new Model 1153 transmitters, the sensed pressure change would have resulted in the same event. In Mr. Dishong's opinion, GSU witness Mr. Sellman had provided reasonable proof that even optimally damped transmitters would have resulted in a reactor scram and shutdown and that the incorrect damping was not the cause of the forced outage. Ex. GS-11A at 4-5. He therefore recommended that the total cost of replacement power for forced outage 94-03 be allowed.

b. Cities' Recommended Disallowance for Outage No. 94-03.

Cities' witness Mr. Richard Hubbard found that a portion of the duration of outage 94-03 should be disallowed because he concluded that the outage was in part the fault of imprudent actions by River Bend management. He testified that the failure to install proper damping in one transmitter and the installation of improper damping in another transmitter was imprudent. Mr. Hubbard testified that the CRD pipe repair activity occurred at the same time GSU undertook corrective action for the vessel water lever transmitters, but that since both the CRD and transmitter work was required due to GSU's unreasonable management, he found that all of the time attributable to these events was imprudently incurred. Additionally, assuming the fuel rod assembly would eventually have caused an outage, Mr. Hubbard and Mr. Wheeler both recommended some allowance to replace the leaking fuel rod assembly. Ex. Cities-48 at 75. Mr. Wheeler recommended allowing approximately 22.5 days as the maximum duration for replacing the fuel rod assembly. Ex. Cities-49. Mr. Hubbard's analysis concluded that because one of the transmitters had damping installed improperly and the other had no damping, the resulting forced outage must have been caused by unreasonable or imprudent management on the part of GSU.