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LARRY CRETUL
Speaker of the House of Representatives

March 12, 2010

Anne Cole, Commission Clerk
And Administrative Services
Room 100, Easley Building
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Re: Docket No. 090505-EI, In re: Review of replacement costs associated with the February 26, 2008 outage on Florida Power & Light's electrical system.

Dear Ms. Cole:

Enclosed for filing in the above-referenced docket are the original and 15 copies of OPC's Request for Official Recognition. A diskette in Word and Adobe Acrobat format is also submitted.

Please indicate the time and date of receipt on the enclosed duplicate of this letter and return it to our office.

Sincerely,

Joe McGlothlin

Joseph A. McGlothlin
Associate Public Counsel

JAM:bsr

COM ___
APA ___
ECR 4
GCL 3+CD
RAD 1
SSC ___
ADM ___
OPC ___
CLK ___

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Review of Replacement Fuel Costs Associated with the February 26, 2008 outage On Florida Power & Light's electrical system	))))	Docket No. 090505-EI Filed: March 12, 2010

OPC'S REQUEST FOR OFFICIAL RECOGNITION

Pursuant to Section 120.569(2)(i), Florida Statutes, the Citizens of the State of Florida, through the Office of Public Counsel, request the Commission to take official recognition of the following orders of regulatory agencies in other states:

Re Gulf States Utilities Company, Texas Public Utility Commission Docket No. 10894, 1993 WL 655241 (1993).

Re Gulf States Utilities Company, Louisiana Public Service Commission Docket No. U-20647, Order No. U-20647': 154 P.U.R. 4th 38 (1994), affirmed in relevant part (and vacated in part on grounds unrelated to this case) in *Gulf States Utilities Co. v. Louisiana Public Service Commission,* 689 So2d 1337 (Louisiana Supreme Court, 1997).

The orders are relevant to the instant case. In the orders, the regulatory agencies addressed, *inter alia,* the impact of the explosion of a transformer used to deliver 12kV energy generated off-site to a nuclear plant when the nuclear generator was shut down on the duration of the outage of the nuclear unit and evaluated whether to adjust associated replacement energy costs.

The orders are attached.

WHEREFORE, OPC requests the Commission to enter an order taking official recognition of the orders cited herein.

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the OPC's Request for Official Recognition has been furnished by electronic mail and U.S. Mail on this 12th day of March, 2010, to the following persons:

Lisa Bennett
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Wade Litchfield
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Joseph A. McGlothlin
Associated Public Counsel

Re: Gulf States Utilities Company

Docket No. U-20647

Order No. U-20647

Louisiana Public Service Commission

July 27, 1994

154 P.U.R.4th 38, 1994 WL 449069 (La.P.S.C.)

Re **Gulf States** Utilities Company
Docket No. **U-20647**
Order No. **U-20647**

Louisiana Public Service Commission
July 27, 1994

ORDER requiring an electric utility to refund some $27 million collected through its fuel adjustment clause.

Most of the refund - approximately $19 million - stems from a prior commission decision to disallow from fuel adjustment charges an 'asset fee' that represented the 'gain' on the transfer of certain utility plants to an affiliated cogeneration company. See, *Re **Gulf States** Utilities Co.*, Order No. U-17282-H, March 1, 1990 (La.P.S.C.), *affirmed sub nom.* ***Gulf States** Utilities Co. v. Louisiana Pub. Service Commission*, 633 So.2d 1258, 151 PUR4th 551 (La.1994).

Commission finds that it is free to review historic fuel clause charges and order refunds for fuel charges imprudently incurred or inappropriately billed through the fuel clause. It explains that retroactive fuel clause refunds do not violate the prohibition against retroactive rate making because fuel clause adjustments are effective without a reasonableness review and are not 'commission-made' rates.

Commission rules that 'explicit approval for [a utility] to collect a cost in rates, or explicit approval of the rate itself, should be required before the rate may be deemed finally approved.' It rejects claims by the utility that commission silence with respect to a rate request constitutes final approval.

Commission disallows some $1.85 million in replacement power costs associated with 'imprudent' forced outages at the River Bend nuclear plant.

The disallowance is based on a prudence standard that requires the utility to act reasonably in all circumstances. Commission rejects the proposed use of a differential, or 'two-tier', prudence standard that would require a higher standard of proof to support a disallowance if the utility's overall performance were at or above some accepted industry standard of average. It also rejects the proposed use of a prudence standard that would require some conscious knowledge of improper conduct on the part of the utility to support a disallowance. Moreover, it finds that contractor negligence should be imputed to the utility in determining prudence, absent unusual circumstances making such an approach unjust.

Commission rejects the novel argument that the imprudent River Bend outages should not lead to cost disallowances because ratepayers are better off when the plant is shut down. **Gulf States** explained that during an outage ratepayers avoid an obligation imposed by prior order to serve as a guaranteed market - and pay 4.6 cents per kWh through the fuel clause - for the output of that portion of the River Bend plant that is not included in rate base. Commission finds that the regulated and deregulated portions of the plant should be kept separate for purposes of prudence damage analysis. However, in light of the utility's evidence that running River Bend causes short-term harm to ratepayers, the commission may consider whether the plant is economic in the long term.

Commission requires the refund of $5.731 million in pipeline capital costs improperly included in the fuel clause as gas transportation costs. The utility may establish a regulatory asset for the pipeline capital costs and the commission will allow recovery of the asset over time as if it were in rate base.

Commission requires the utility to refund $446,000 in interest on a previously refunded overcollection where the overcollection resulted from errors by the utility.

The utility is ordered to refund $13.1 million of the total $27 million in fuel clause disallowances in its next billing cycle. The refund of the remaining portion of the disallowance is suspended pending rehearing, or the expiration of the time allowed for filing for rehearing.

P.U.R. Headnote and Classification

1.
AUTOMATIC ADJUSTMENT CLAUSES

s11
La.P.S.C. 1994
[LA.] Fuel adjustment clause charges - Exclusion of asset fee - *Gain on transfer of utility assets* - Refund - Electric utility.
Re **Gulf States** Utilities Company

P.U.R. Headnote and Classification

2.
AUTOMATIC ADJUSTMENT CLAUSES

s58
La.P.S.C. 1994
[LA.] Retroactive application - Fuel clause charges - Refund of imprudently incurred costs - Refund of inappropriately billed charges - Legality - Electric utility.
Re **Gulf States** Utilities Company

P.U.R. Headnote and Classification

3.
AUTOMATIC ADJUSTMENT CLAUSES

s64
La.P.S.C. 1994
[LA.] Findings and decisions - Fuel clause charges - Reasonableness review - Retroactive refunds - 'Commission-made' rate doctrine - Electric utility.
Re **Gulf States** Utilities Company

P.U.R. Headnote and Classification

4.
RATES

s250
La.P.S.C. 1994
[LA.] Retroactive rate-making - Refund of fuel adjustment charges - Legality - 'Commission-made' rate doctrine - Electric utility.
Re **Gulf States** Utilities Company

P.U.R. Headnote and Classification

5.
AUTOMATIC ADJUSTMENT CLAUSES

s11
La.P.S.C. 1994
[LA.] Fuel adjustment clause charges - Retroactive refunds - Legality - Electric utility.
Re **Gulf States** Utilities Company

P.U.R. Headnote and Classification

6.
RATES

s650
La.P.S.C. 1994
[LA.] Practice and procedures - Findings and decisions - Finality - Fuel adjustment charges - Silence as approval - Explicit approval required.
Re **Gulf States** Utilities Company

P.U.R. Headnote and Classification

7.
AUTOMATIC ADJUSTMENT CLAUSES

s64
La.P.S.C. 1994
[LA.] Practice and procedure - Findings and decisions - Finality - Fuel adjustment charges - Silence as approval - Explicit approval required.
Re **Gulf States** Utilities Company

P.U.R. Headnote and Classification

8.
AUTOMATIC ADJUSTMENT CLAUSES

s11
La.P.S.C. 1994
***40** [LA.] Fuel adjustment clause charges - Exclusion of asset fee - Gain on transfer of utility assets - Calculation of refund - Refund period - Order on remand - Electric utility.
Re **Gulf States** Utilities Company

P.U.R. Headnote and Classification

9.
AUTOMATIC ADJUSTMENT CLAUSES

s57
La.P.S.C. 1994
[LA.] Refunds - Method of calculation - Appropriate refund period - Disallowed charges - Fuel adjustment clause - Order on remand - Electric utility.
Re **Gulf States** Utilities Company

P.U.R. Headnote and Classification

10.

AUTOMATIC ADJUSTMENT CLAUSES

s58
La.P.S.C. 1994
[LA.] Retroactive application - Fuel clause charges - Refund of inappropriately billed charges - 'Asset fee' on transferred utility plants - Calculation of refund - Refund period - Collections prior to explicit disallowance - Electric utility.
Re **Gulf States** Utilities Company

P.U.R. Headnote and Classification

11.
EXPENSES

s122
La.P.S.C. 1994
[LA.] Electric utility - Nuclear outages - Forced outages - River Bend plant - Replacement power costs - Prudence standard - Contractor imprudence - Imputation to utility.
Re **Gulf States** Utilities Company

P.U.R. Headnote and Classification

12.
AUTOMATIC ADJUSTMENT CLAUSES

s13
La.P.S.C. 1994
[LA.] Replacement power costs - Nuclear outage - Forced outages - River Bend plant - Prudence standard - Contractor imprudence - Imputation to utility - Electric utility.
Re **Gulf States** Utilities Company

P.U.R. Headnote and Classification

13.
EXPENSES

s17
La.P.S.C. 1994
[LA.] Reasonableness - Prudence standard - Outage expense - Forced outages - Contractor imprudence - Imputation to utility.
Re **Gulf States** Utilities Company

P.U.R. Headnote and Classification

14.
EXPENSES

s15
La.P.S.C. 1994
[LA.] Reasonableness - Prudence standard - Single versus differential standard - Electric utility.
Re **Gulf States** Utilities Company

P.U.R. Headnote and Classification

15.
EXPENSES

s122
La.P.S.C. 1994
[LA.] Electric utility - Nuclear outages - Forced outages - River Bend plant - Imprudence disallowance - Proposed offset by ratepayer savings - Savings associated with shutdown of deregulated portion of plant - Electric utility.
Re **Gulf States** Utilities Company

P.U.R. Headnote and Classification

16.
AUTOMATIC ADJUSTMENT CLAUSES

s13
La.P.S.C. 1994
[LA.] Replacement power costs - Nuclear outage - Forced outages - River Bend plant - Imprudence disallowance - Proposed offset by ratepayer savings - Savings associated with deregulated portion of plant - Electric utility.
Re **Gulf States** Utilities Company

P.U.R. Headnote and Classification

17.
AUTOMATIC ADJUSTMENT CLAUSES

s11
La.P.S.C. 1994
[LA.] Fuel clause - Gas transportation expense - Exclusion of pipeline capital costs - Refund requirement - Electric utility.
Re **Gulf States** Utilities Company

P.U.R. Headnote and Classification

18.
AUTOMATIC ADJUSTMENT CLAUSES

s57
La.P.S.C. 1994
[LA.] Fuel clause - Refunds - Improperly included charges - Pipeline capital costs - Electric utility.
Re **Gulf States** Utilities Company

P.U.R. Headnote and Classification

19.
AUTOMATIC ADJUSTMENT CLAUSES

s57
La.P.S.C. 1994
[LA.] Overcollection due to utility error - Refund - Interests - Electric utility.
Re **Gulf States** Utilities Company

Before Blanco, chairman, Schwegmann, vice chairman, and Powell, Owen, and Dixon, commissioners.

***41** BY THE COMMISSION:

This proceeding involves an investigation of the prudence of charges flowed by **Gulf States** Utilities Co. ('**Gulf States**' or 'GSU') through its fuel adjustment clause. The Commission retained Stone, Pigman, Walther, Wittmann & Hutchinson as Special Counsel and Kennedy & Associates as expert consultants to investigate the prudence of these costs. The investigation focused on fuel clause charges from October, 1988 through September, 1991.

[1] This order requires refunds of approximately $27 million for the period of the fuel clause review. GSU is ordered to refund $13.1 million of the $27 million immediately. The remaining portion of the $27 million refund is suspended to give **Gulf States** the opportunity to move for a rehearing. If GSU chooses not to file a motion for rehearing, the remaining portion of the $27 million is to be refunded in the billing cycle following the expiration of the time allowed for the motion. Most of the refund - about $19 million - relates to a double recovery obtained by **Gulf States** on investments it transferred to the Nelson Industrial Steam Co. ('NISCO'). The Commission's decision to disallow the double recovery for part of the period at issue was recently upheld by the Louisiana Supreme Court. ***Gulf States** Utilities Co. v. Louisiana Public Service Com'n,* 633 So. 2d 1258 (La. 1994). The remainder of the proposed refund is based largely on the recommendations of the Commission's consultant, Lane Kollen, although some of the recommended disallowances have been modified.

I. BACKGROUND

A. Introduction

[2][3][4][5] The Commission's decision to investigate GSU's fuel clause filings was prompted by a disallowance of the Texas Public Utilities Commission and also by concerns regarding increased fuel expense caused by prolonged River Bend outages.

In April, 1993 the Texas PUC completed a fuel clause investigation and ordered refunds. The Texas PUC disallowed approximately $116 million on a total company basis. Most of the Texas disallowance, $107 million, related to charges in excess of avoided cost paid by GSU to NISCO for electricity from the Nelson 1 and 2 gas units. Additional Texas disallowances related to the incremental cost of fuel associated with various River Bend outages, failure to reflect a fuel clause credit from profits associated with off-system sales, and failure to reduce fuel costs to reflect revenues associated with Big Cajun 2 Unit 3 generation sold to Cajun.

Additionally, in 1993 this Commission became aware that GSU was having difficulty managing River Bend. GSU was fined by the Nuclear Regulatory Commission in the Summer of 1993, and later was forced to shut down River Bend because of operational problems. [Docket No. U-20565 Tr. 8/26/93 at 5, 22-23]. Since nuclear fuel is the least costly fuel used by **Gulf States**, River Bend outages force GSU to rely on more costly fuel for electric generation. The Commission held a hearing and questioned the company about the forced outage, and the company voluntarily provided a refund. The circumstances of the 1993 outage, and whether additional refunds are warranted based on River Bend performance in 1993, will be investigated in the next phase of the GSU fuel clause review, which is currently scheduled to commence in January, 1995. This Order discusses River Bend's performance from October, 1988 through September, 1991.

These concerns, coupled with a recent judicial affirmation of the Commission's jurisdiction to examine fuel clause filings, prompted the Commission to investigate GSU's fuel clause charges. In *Daily Advertiser v. Trans-La, etc.*, 612 So. 2d 7 (La. 1993) the Louisiana Supreme Court affirmed the use of the automatically adjustable fuel clause as a ratemaking tool. The Court emphasized that the Commission's jurisdiction to examine fuel clause filings retrospectively, and make retroactive refunds, does not violate the rule against retroactive ratemaking.

The fuel adjustment clause is used by many utilities. It is a rate component that is automatically adjusted, either up or down, in relation to fluctuations in operating expenses. ***42** Use of an automatically adjustable fuel clause enables the utility to charge rates that closely and promptly follow fuel expense. Thus, problems associated with regulatory lag are ameliorated. *Daily Advertiser* explained:

Commissions employ such clauses when they encounter an item of expense, such as fuel costs, that tends to be more volatile in comparison to the utility's other costs. Such clauses permit fluctuations in the utility's costs to be passed through directly to its customers as cost adjustments in subsequent utility bills. Such clauses thereby permit the utility to track its rates more closely to its current cost of fuel without continually having to file for rate increases (or decreases), ameliorating the regulatory lag problem inherent in the prospective nature of ratemaking.

Id. at 22 (citations omitted).

The prohibition against retroactive ratemaking does not apply to fuel clause analyses. *Id*. at 24. Thus, the Commission is free to review historic fuel clause charges and order refunds for charges imprudently incurred or inappropriately billed through the fuel clause. *Id*. at 25. Retroactive refunds do not violate the prohibition against retroactive ratemaking, because fuel clause adjustments are effective without a reasonableness review and are not 'commission-made' rates. *Id*. at 23-24. Since the fuel clause benefits the utility by ameliorating regulatory lag, the courts generally agree that commissions should not be prevented from reviewing fuel clause charges for reasonableness at a later time. *Id*. at 24. *See also* *Southern California Edison Co. v. California Public Utilities Commission*, 20 Cal. 3d 816, 144 Cal. Rptr. 905, 576 P. 2d 945 (1978).

Shortly after this docket was opened, representatives of GSU met with the Commission staff and consultants to discuss procedures for the investigation. The company requested that the Commission separate its review into two phases. According to GSU representatives, a two-phase review would expedite the Commission's proceeding, since the first phase could utilize the record from the 1993 Texas PUC proceeding. The Commission staff agreed to divide the review into two phases. The first phase, which is the subject of this Order, is a review of fuel clause charges from October, 1988 through September, 1991. Utilizing the same time period as the recently completed Texas investigation helped alleviate GSU's burden of responding to requests for information because most of the data had previously been produced in the Texas proceeding. GSU agreed to file direct testimony on fuel clause issues relating to the record compiled by the Texas PUC. The second phase of the fuel clause review will analyze fuel clause charges from October, 1991, forward, in connection with the GSU post-merger rate review occurring in Docket No. U-19904. The second phase will commence in January, 1995.

B. Testimony.

Mr. Lane Kollen of Kennedy & Associates filed three pieces of testimony on behalf of the Commission staff: Direct Testimony, dated January 21, 1994; Surrebuttal Testimony, dated April 8, 1994 and Supplemental Surrebuttal Testimony, dated April 25, 1994. In contrast, GSU presented seventeen pieces of testimony through eight witnesses, and filed testimony on six different filing dates. GSU's filing history is set forth below:

GSU TESTIMONY

LPSC DOCKET NO. ***U-20647***

Testimony	*Name*	*Date*
Direct	Mr. Willis	December 14, 1993
Direct	Mr. Suhrke	December 14, 1993
Direct	Mr. Louiselle	December 14, 1993
Direct	Mr. Champagne	December 14, 1993
Direct	Mr. Beekman	December 14, 1993
Rebuttal	Mr. Willis	February 23, 1994

Rebuttal	Mr. Beekman	February 23, 1994
Rebuttal	Mr. Freehill	February 23, 1994
Rebuttal	Mr. Derbonne	February 23, 1994
Rebuttal	Mr. Champagne	February 23, 1994
Rebuttal	Mr. Louiselle	February 23, 1994
Rejoinder	Mr. Freehill	April 22, 1994
Rejoinder	Mr. Derbonne	April 22, 1994
Rejoinder	Mr. Willis	April 29, 1994
Rejoinder	Mr. Louiselle	May 3, 1994
Rejoinder	Mr. Harrington	May 5, 1994
Rejoinder	Mr. Beekman	May 5, 1994

***43** Contrary to the agreement reached with the Commission staff, **Gulf States**' direct testimony was very general, and did not address issues forming the basis for the Texas refund. GSU did not address or identify specific issues relating to River Bend outages during the Phase I review period, nor did the company analyze the issues that were litigated in Texas. GSU addressed the issues raised in Texas for the first time in rebuttal testimony, which made it necessary for Mr. Kollen to respond and led to additional filings by the company.

Mr. Bruce Louiselle is the only GSU witness who addressed River Bend performance in the company's direct case. However, Mr. Louiselle did not discuss outages, nor did he address the impact of outages on Louisiana fuel clause expenses in view of the Louisiana rate base exclusion plan. Rather, Mr. Louiselle's direct testimony focused on overall plant performance. The company filed direct testimony of four other witnesses.

The Commission Staff's direct case consisted of the testimony of Mr. Lane Kollen. Mr. Kollen recommended disallowance of incremental costs associated with imprudence and mismanagement of refueling outages at the River Bend nuclear unit. Mr. Kollen also recommended a refund based on GSU's recovery of the gain on the sale of the Nelson 1 and 2 units included in payments to NISCO, contrary to LPSC Order No. U-17282-H. Mr. Kollen recommended that GSU report to the Commission when litigation between GSU and Cajun over excessive Big Cajun 2 Unit 3 coal costs is resolved. Mr. Kollen found that GSU recovers base rate costs through the fuel clause. He recommended that the Commission adopt guidelines regarding allowable fuel costs, and that costs be realigned from the fuel clause to base rates. Mr. Kollen also recommended that GSU update the interest rate for over and under recoveries to reflect the capital structure utilized in Order U-17282 (J), until the capital structure is modified.

GSU sponsored the testimony of six witnesses to rebut Mr. Kollen's direct testimony, and the company raised new issues on rebuttal. Mr. Bruce Louiselle testified that the extended outages at River Bend were not based on imprudence, and that the outages actually produced a net benefit to ratepayers. Mr. Beekman testified that the company's fuel clause filings were reviewed by Commission staff and that prior orders of the Commission approved GSU's treatment of under and over recoveries and non-fuel purchased power costs. Mr. Willis also testified that prior Commission orders ***44** authorized GSU's fuel clause practices, and requested that any refunds be included in the over/under recovery balance for a 12-month period. Mr. Champagne provided rebuttal testimony on various issues that Mr. Kollen indicated needed further clarification, including transportation costs paid to Sabine Gas Transmission Co. Mr. Peter E. Freehill and Mr. Donald R. Derbonne sponsored rebuttal testimony addressing Mr. Kollen's assertions of mismanagement associated with River Bend outages.

Mr. Kollen refined and modified his recommendations in surrebuttal testimony. He recommended disallowance of incremental costs associated with forced and/or extended River Bend outages, interest associated with the River Bend Cajun buybacks, gas pipeline capital costs that were improperly collected in the fuel clause, and the gain on the sale of assets to NISCO.

The company filed several pieces of rejoinder testimony addressing the issues discussed by Mr. Kollen.

C. Hearings.

There were no intervenors. The company and the Commission Staff exchanged data requests and participated in depositions. Mr. Robert E. Crowe of the Commission staff presided over the hearings, which were conducted on May 24 and 25, 1994. Messrs. Kollen, Louiselle, Derbonne and Beekman were cross-examined at the hearings. The depositions of Messrs. Champagne, Willis, Freehill and Harrington were admitted into the record in lieu of live cross-examination.

D. Motions.

The Commission staff objected to GSU's filing of rejoinder testimony, and requested that the rejoinder testimony be stricken from the record. [Corresp. 4/18/94, Michael R. Fontham to Marshall B. Brinkley]. GSU moved to strike portions of the direct and surrebuttal testimony of Mr. Kollen, and also moved to strike Mr. Kollen's surrebuttal in its entirety in the event that the company's rejoinder testimony is stricken. [GSU Motion to Strike, April 21, 1994]. The Commission rejects both requests, and orders that all pre-filed testimony be admitted into the record.

Gulf States moved to strike portions of Mr. Kollen's testimony regarding the types of costs that should be recoverable through the fuel clause, and portions of testimony in which he recommended that the Commission adopt guidelines regarding costs that are includable in the fuel clause. The company also requested that Mr. Kollen's recommendation of cost realignment be stricken. GSU based its request on the argument that this proceeding is a review of past charges, and not a general rule making proceeding. GSU also argued that since Mr. Kollen does not recommend that the Commission realign costs in this proceeding, the testimony is gratuitous. [GSU Motion To Strike].

GSU's motion to strike is denied. Kennedy & Associates was hired to investigate the practices used by **Gulf States** in connection with computing its fuel adjustment factor. It was not hired merely as an accounting firm to check numbers presented by GSU. Thus, the information provided in Mr. Kollen's testimony is relevant to the issues that Mr. Kollen was hired to investigate.

Additionally, GSU filed its motion to strike *after* responding to the testimony it is requesting be stricken. GSU filed numerous pieces of testimony, several witnesses were cross-examined at the hearing, and various depositions were admitted into the record. Striking Mr. Kollen's testimony regarding any issue would require exhaustive review of all other material in the record to insure that all rebuttal references to the stricken testimony were also deleted. Such a procedure would be costly, time-consuming, and an unnecessary waste of resources.

Furthermore, the testimony is informative, and provides an overview of possible parameters of legitimate fuel clause charges. While Mr. Kollen does not recommend that the Commission take action regarding realignment of costs in this proceeding, he does recommend that the Commission adopt guidelines for cost recovery and recommends that costs be realigned in the post-merger review of GSU. This testimony is ***45** an appropriate basis for future action by the Commission.

Moreover, the staff is willing to withdraw its objection to GSU's rejoinder testimony, if the Commission denies GSU's Motion to Strike. The basis for Special Counsel's objection to the rejoinder testimony is essentially that the testimony was filed out of time. The procedural schedule promulgated by the Commission - and agreed to by GSU - did not provide for the filing of rejoinder testimony.

The company responded to the Commission's objection to GSU's rejoinder testimony by arguing that since GSU had the burden of proof, GSU was entitled to open and close the record. According to the company, since Mr. Kollen provided surrebuttal testimony, it was necessary for the company to file rejoinder testimony. [GSU Motion To Strike]. Therefore, GSU moved that if its rejoinder testimony was stricken, Mr. Kollen's surrebuttal testimony should also be stricken.

The company's argument is unfounded. The Commission often conducts proceedings where staff is allowed to file the final testimony, even when the utility has the burden of proof. Additionally, Mr. Kollen's surrebuttal testimony was only necessary because of GSU's dilatory tactic in not providing substantive information in its direct case. Since GSU did not address specific issues on direct, Mr.

Kollen was forced to identify the issues and seek information from the company. More forthright cooperation by GSU in the beginning of the proceeding would have alleviated the work that was required at its end. Nonetheless, since the testimony now is all in the record, and both sides have had the opportunity to address all the issues, the Commission will not attempt to expurgate parts of it.

Thus, the Commission denies GSU's Motion to Strike Portions of Mr. Kollen's testimony and dismisses the Staff's objection to the filing of GSU's rejoinder testimony.

*II. **GULF STATES**' 'SILENCE IS APPROVAL' REGULATORY THEORY*

[6][7] **Gulf States** relied heavily in this case on a novel regulatory interpretation of the Commission's orders. It asserted that silence by the Commission is an approval of the company's requests, almost regardless of how they are expressed. This regulatory theory should not be used when interpreting orders of this Commission.

According to Mr. David Beekman, Manager of GSU's Regulatory Affairs, if the Commission does not affirmatively deny a request sought by the company in a base rate proceeding, the company deems that the request is approved. [Beekman Rej. Test. at 5-6]. Thus, if a Commission order does not contain specific approval, but neither accepts nor rejects the company's proposal, GSU regards the proposal as accepted. [Tr. 5/24/94 (Mr. Beekman) at 18]. Apparently, the company's request does not have to be in an application, nor is it necessary that the request be in the company's testimony or exhibits. Under some circumstances, according to the company, it might be sufficient if the request is simply put into the record in a data request response. [*Id.* at 18-21]. GSU's regulatory theory does not apply to proposals made by Commission Staff, consultants, intervenors, or ratepayers. [*Id.* at 21-23]. If the Commission's order is silent with respect to a contested Staff or intervenor recommendation, the proposal would be deemed to be rejected by GSU. [Beekman Rej. Test. at 6].

For example, in this proceeding Mr. Kollen testified that costs associated with Nelson 6 and Big Cajun II Unit 3 should be considered 'non-fuel' costs, and should be in base rates, not the fuel clause. During the review period these charges totalled $5.678 million. [Kollen Dir. Test. at 26]. GSU stated that the Commission authorized including certain costs in the fuel clause in Docket No. U-15271. [Willis Dir. Test. at 8; Willis Reb. Test. at 2; Willis Rej. Test. at 2-3]. The company set forth the rebuttal testimony of Bobby Joe Willis, who stated that he proposed that the 'non-fuel' costs be recovered through the fuel clause in Docket No. U-15271, and that the Commission had approved such treatment. [Willis Reb. at 3].

However, the Commission's orders in that docket make *no* reference to approval of charging the 'non-fuel' costs to ratepayers through the fuel clause. [Orders Nos. U-15271, U-15271-(A), and 15271-(B), Willis Depo. ***46** (3/23/94) Exs. 2-3]. In deposition, Mr. Willis was apparently confused about whether the company actually even requested the approval that it said was granted by the Commission's orders. Mr. Willis admitted that today he would more clearly state that the company intended to pass the charges through the fuel clause. [Willis Depo. (3/23/94) at 91-99].

The company attempted to clarify the matter in rejoinder testimony. According to Mr. Willis' rejoinder, the company indicated in testimony that at least some of the 'non-fuel' costs would be charged to Account 501. [Willis Rej. Test. at 2]. However, Mr. Willis admitted in deposition that not all charges recorded in Account 501 are flowed through the fuel clause. [Willis Depo. (3/23/94) at 84]. Thus, there is no reference in testimony of any intent of the company to flow all the 'non-fuel' charges in question through the fuel clause. The only reference in Docket No. U-15271 of the company's desire to flow the 'non-fuel' items through the fuel clause was in a data response. [Willis Rej. Test. at 2-3]. The inclusion of this intention in a data response assertedly was deemed 'approval' of the company's action in view of the Commission's silence on the matter in its Order.

Another example of GSU's use of this theory is its interpretation of the Commission's order regarding the Spindletop Gas Storage Project. The company contends that the Commission approved fuel clause flow through of capital charges associated with the Spindletop Gas Storage Project in Docket No. U-18903. However, Order No. U-18903 does not discuss fuel clause flow through of capital costs. LPSC

Order No. U-18903. The company did not file an application indicating that the capital charges associated with Spindletop would be flowed through the fuel clause, nor was fuel clause treatment discussed at the hearing. [LPSC Exs. 1, 2, 3]. Nevertheless, GSU contends that the Commission's silence effectively approved the action it chose to take. Moreover, it contended that this silence approved *prior* incidents in which **Gulf States** unilaterally flowed capital-related costs through the fuel clause.

The Louisiana Supreme Court refused to adopt GSU's logic in GSU's appeal of the NISCO decision. ***Gulf States** Util. Co. v. Louisiana Public Serv. Comm'n*, 633 So. 2d 1258 (La. 1994). In that case, the Court rejected GSU's assertion that the Commission's approval of the NISCO contract included an implicit approval of all contract costs recovered by GSU through the fuel adjustment clause. *Id.* at 1262. GSU argued that the Commission could not exclude the payments representing a double recovery to GSU, because the Commission had 'approved' the proposed collection of the gain through the fuel clause when it approved the NISCO contract. *Id.* at 1262. The Court held that the Commission's approval of the contract could not be viewed as precluding future adjustments of the rates GSU charged to ratepayers, although there was an indication of **Gulf States'** intention to recover contract costs through the fuel clause. *Id.* at 1263. The case is discussed further in Section III.

GSU's theory is incorrect. Explicit approval for the company to collect a cost in rates, or explicit approval of the rate itself, should be required before the rate may be deemed finally approved. If the company believes an order is unclear, it should request clarification from the Commission. No basis exists for a one-sided rule that approves all utility requests unless they are denied, but denies all other requests unless they are approved.

III. NISCO REFUND ISSUE

[8][9] In 1986 **Gulf States** entered into an agreement with three of its industrial customers. The customers had been considering the generation of their own electric requirements and **Gulf States** wished to maintain their load on its system. The three customers - Conoco, Inc., Citgo Petroleum Corp., and Vista Chemical Co. - entered a joint venture with **Gulf States** to create the Nelson Industrial Steam Company ('NISCO'). NISCO agreed to purchase two generating units at the Nelson station in Lake Charles, Louisiana, Nelson 1 and 2. In turn, **Gulf States** agreed to purchase electricity from the joint venture, which initially would generate the electricity from the Nelson units, but subsequently would construct and use coal-fired generation.

Gulf States sought approval of the proposed ***47** transaction from the Commission in 1986. The application requested that the contract for the joint venture and the sale of electricity be accepted. The contract contained a complex formula for computing the payments **Gulf States** would make to the joint venture for electricity. **Gulf States** stated in its application that payments to NISCO would be included in its fuel clause, but did not quantify the payments, seek approval of specific costs or rates, or specify the rates that the company would attempt to recover from customers. The Commission approved the application for approval of the contract in an Order issued July 1, 1987; it did not expressly approve the inclusion of any amounts in the fuel clause.

In the third phase of the Commission's phase-in of the River Bend nuclear unit, the Commission's consultants reviewed the company's non-River Bend operations. They determined that **Gulf States** had realized a substantial gain on the sale of the Nelson generators to NISCO, which the company kept for its shareholders. NISCO obligated itself to pay $6.35 million per year for 20 years for the generators; the present value of this payment stream was about $48.5 million. After deducting the book value of the Nelson 1 and 2 units, the expenses of the sale, and the cost of common facilities transferred out of utility plant, the gain was about $41.5 million. [*See* GSU Ex. DNB-2, p. 1 to Beekman Rej. Test.].

The consultants also determined that the 'asset fee' payments were being billed back to **Gulf States** in the cost of electricity and included by the company in its fuel costs. Since the ratepayers already had paid once for the amount reflected as a gain, the consultants recommended that the Commission disallow any double recovery for the Nelson units. In Order No. U-17282-H, the Commission disallowed the double recovery of the gain. It stated:

Ratepayers already paid once for the Nelson units through depreciation reflected in base rates; they should not be required to pay twice. Further, the fuel clause issue relating to the NISCO sale was not fully analyzed in the prior proceeding. Therefore, **Gulf States** will be directed not to include to [sic] gain-related payments in its fuel costs.

*Ex parte **Gulf States** Utilities Co.*, Order No. U-17282-H at 33 (La. P.S.C. March 1, 1990).

Gulf States sought injunctive relief and appealed in the Nineteenth Judicial District Court for the Parish of East Baton Rouge. The company obtained an injunction preventing the Commission from disallowing the double recovery of the NISCO asset fee in the fuel clause. Subsequently, the district court overruled the Commission's decision and made the injunction permanent, finding that the Commission's approval of the contract constituted an approval of fuel cost recovery for all costs assessed **Gulf States** under the contract. ***Gulf States** Utilities Co. v. Louisiana Public Service Comm'n*, No. 355, 527 (19th J.D.C.) (Oral Reasons for Judgment). The Commission appealed to the Louisiana Supreme Court.

On March 17, 1994, the Supreme Court overruled the injunction and affirmed the Commission's disallowance. It determined that the approval of the NISCO sale was not an approval of fuel clause recovery of any costs passed through the contract. It stated that the 'Commission, in the proceeding leading to the order approving the NISCO contract, simply did not purport to fix the elements of the fuel adjustment clause for the next twenty years.' ***Gulf States** Utilities Co. v. Louisiana Public Service Comm'n*, 633 So. 2d 1258, 1262-63 (La. 1994). Further, the Court ruled:

We conclude that the Commission's order approving the NISCO contract essentially approved the transfer of the units and the general formula for GSU's purchase price of electricity from NISCO, without granting untouchable status for twenty years to the fuel adjustment clause. The NISCO contract contained complex formula for calculating the rates GSU paid NISCO for electricity at various stages over the twenty-year contract. The Commission's approval of the contract for GSU's purchasing electricity from NISCO could not be viewed as precluding the Commission's future adjustments of the rates that GSU charged to ratepayers.

***48** *Id.* at 1263.

The Court also determined that the Commission's action did not constitute an illegal impairment of the NISCO contract. It determined that the expected fuel clause treatment was not the primary motivation for the contract. More important, the Court found that the Commission could exercise its power to prevent a double recovery in promotion of the public interest. The Court ruled:

Moreover, the Commission exercised its rate-making power in this case to remedy GSU's unusual use of the fuel adjustment clause to recover original investment costs which GSU had already recouped from the ratepayers. Any contractual obligations impaired in this case must yield to the Commission's exercise of its regulatory powers for the promotion of the public good .

Id. at 1264-1265.

A similar observation was made by a concurring justice, who determined the Commission should not be estopped from adjusting the rate. He determined, in part: '[W]ithout the later adjustment in the rate case, it appears that GSU would have received an undeserved windfall at the ratepayers' expense.' *Id.* at 1267 (Dennis, J., concurring).

Since the ***Gulf States*** NISCO case was decided during the Phase 1 investigation of the company's fuel charges, hearings on the remand were conducted in this proceeding. Two primary issues are presented: 1) What is the appropriate calculation of the refund due for the period after the issuance of the district court's preliminary injunction overruling the NISCO disallowance? - the 'remand' issue, and 2) Should the double recovery be disallowed in Phase 1 for time period preceding Order No. U-

17282-H, which was issued March 1, 1990?

A. NISCO Remand Issue.

Both Lane Kollen of Kennedy & Associates and David Beekman of **Gulf States** presented calculations of the amount due ratepayers pursuant to the remand. Mr. Kollen calculated the Louisiana overcollection, from April, 1990 through May, 1994, to be $11,348,000. With interest his recommended refund was $14,636,000. Mr. Beekman agreed that the NISCO double recovery should be refunded under the Supreme Court's analysis, but took issue with aspects of Mr. Kollen's calculation. He calculated the overcollection to be $10,207,334 and the total refund, with interest, to be $13,137,196.

The difference in the calculations relates primarily to the treatment of the non-gain portion of the total amount realized in the NISCO sale. The total present value sales price, reflecting the 20-year payment of the annual 'asset fee' of $6.35 million, was $48,539,195. The price was offset by certain costs of **Gulf States**, including the undepreciated book value of Nelson 1 and 2 ($595,720), the expenses of the sale ($992,575), and the net book value of common facilities at the NISCO station transferred by GSU from utility plant into non-utility plant ($5,513,798). Additionally, more common facilities were transferred as of January 1, 1992, having a net book value of $2,920,897.

Mr. Kollen took the costs offsetting the sales price, divided the total by 20 years and offset them against the annual asset fee. For the period before the 1992 transfer of common facilities, the offsetting amount was about $350,000 per year; for the subsequent period, it was about $490,000 annually. [Kollen Supp. Surr. Test. at 3]. Thus, the 'gain' in the first few years calculated by Mr. Kollen was $6.0 million on a total company basis; subsequently it was $5.832 million. [*Id.*].

Mr. Beekman took issue with Mr. Kollen's calculation, arguing that it denied the company the appropriate value of the non-gain portion of the sales price. According to Mr. Beekman, the sales price realized in the transaction reflects a discounted present value of the stream of annual asset fees. Thus, it is equivalent to a cash price that **Gulf States** might have received on the date of the sale. He argues that Mr. Kollen's amortization of the offsetting amounts, without interest over 20 years, has the effect of denying the company the full value of the assets transferred as of the date of the sale. In other words, the present value of the recovery stream ***49** for the offsetting costs is less than the total of the transaction expense and the book value of the investments as of the time of the sale. Mr. Beekman recommended that these amounts offset the gain as of the time of the sale in calculating the portion of the asset fees allocated to ratepayers. [Beekman Rej. Test. at 17-19].

In concept, Mr. Beekman's argument is correct. The asset fee payment stream includes the equivalent of interest. Calculating offsets to the payment stream without interest has the effect of denying shareholders the time value of the money they recover. On the other hand, the largest share of the offsets is attributable to the common facilities **Gulf States** transferred from utility to non-utility plant. The company's stockholders have not lost the ownership of that plant. They conceivably could realize value for the common facilities if they are sold to NISCO or some other party. To the extent the value of the common facilities offsets the refund, and **Gulf States** realizes additional value for the facilities, the transaction also would produce a double recovery to shareholders.

Rather than adopting either of these positions, the Commission will calculate the refund so that ratepayers pay no more than they would have paid for the Nelson units and the common facilities if the NISCO transaction had not occurred. Under this analysis, Mr. Beekman's calculation of the offsets should be adopted, because ratepayers would have paid **Gulf States** a return of and on the investment in the plant and the common facilities until they were fully depreciated. On the other hand, allowing **Gulf States** a recovery of the common facilities, with a carrying charge, means that those facilities are still owned for the ratepayers' benefit. If the company does sell or transfer the units for value, the amount received should go to benefit ratepayers.

The expense incurred by **Gulf States** in connection with the transaction is a different story. If the sale had never occurred, ratepayers would not have been required to pay the expense. Nevertheless, an argument can be made that **Gulf States** should be entitled to some recovery of the expense, since the NISCO transaction was assertedly undertaken partly for the ratepayers' benefit. The transaction also was undertaken to benefit shareholders, however, and they should bear a fair proportion of the cost. Mr. Kollen's methodology of allowing a recovery of, but not on, the expense will be used for this category of cost, as it fairly apportions the cost between the company and ratepayers.

With respect to the additional common facilities transferred to non-utility plant as of January 1, 1992, both Mr. Kollen and Mr. Beekman allowed some setoff for the investment in this plant. The Commission will not accept either calculation. As Mr. Beekman conceded at the hearing, that plant was in rate base at the time of **Gulf States**' last general rate review and has never been removed. [Tr. 5/24/94 at 38-39]. **Gulf States** did not reduce base rates for the removal of the plant from utility plant. Yet using this investment to offset the refund calculation in effect allows a double recovery through the fuel clause. Mr. Beekman testified:

Q. Mr. Beekman, in connection with the January 1, 1992 transfer of common facilities from plant in service to non-utility plant, did the company seek a base rate reduction?

A. No sir.

Q. Base rates were not reduced to reflect the removal of that plant from plant in service, is that right?

A. Nor were they increased to reflect any other costs that may have occurred.

Q. Yet as of January 1, 1992, you want to include this plant in the amounts that would be recovered through the fuel clause, is that right?

A. It would affect the amount of credit due ratepayers through the fuel clause, yes.

[Tr. (5/24/94) at 39].

The Commission will disallow any credit against the fuel clause reduction for the common facilities transferred January 1, 1992, at least until a base rate proceeding in which these facilities are excluded from rate base. This action is necessary to avoid the requirement that ratepayers pay twice for the same plant.

Applying the above principles, the Commission will require a refund of the Louisiana ***50** portion of about $459,492 per month for the post-injunction period. The amount is approximately $10.6 million. With interest, the approximate refund is about $13.7 million. **Gulf States** is required to submit a refund calculation consistent with the requirements of this recommendation, including any necessary adjustments for the period subsequent to April, 1994, and to adjust its fuel clause recovery for consistency with the order. The Commission orders that $13.1 million be refunded immediately, and will allow GSU to seek rehearing prior to refunding the entire amount. The $13.1 million figure should be updated to reflect interest as of the date the refund is made. If GSU does not file a timely motion for rehearing, the remaining amounts should be refunded upon expiration of the period for filing for rehearing.

B. NISCO Recoveries Prior to Order No. U-17282-H.

[10] The decision of the Supreme Court raises a related issue: What is the appropriate treatment of the asset fees recovered through the fuel clause prior to the Commission's March 1, 1990 rate order? **Gulf States** began including the cost of purchases from NISCO in its fuel recoveries near the beginning of the Phase 1 review period. Thus, it achieved a double recovery of the investment in Nelson 1 and 2 during most of Phase 1. The refund discussion above does not address the period from October, 1988 through March, 1990.

Mr. Kollen recommended that the Commission consider disallowing 'the Company's recovery of the gain portion of the fixed asset fee prior to its Docket No. U-17282-H order.' [Kollen Supp. Surr. Test. at 4]. He calculated the total potential refund to be $5.680 million, including $3.251 million of over recoveries and $2.429 million of interest.

Gulf States responded to this recommendation of Mr. Kollen by contending that the disallowance of collections prior to Order No. U-17282-H would constitute retroactive ratemaking. Mr. Beekman asserted that the Commission chose not to allocate the gain to ratepayers when it approved the NISCO sale in 1987, and did not address the issue in a 1987 rate order on River Bend. Thus, he asserts the Commission 'chose not to' disallow the double recovery in 1987. [Beekman Rej. Test. of at 25-26]. Bruce M. Louiselle, another **Gulf States** witness, asserted that Mr. Kollen's suggestion is a 'clear example of retroactive ratemaking,' apparently because Order No. U-17282-H did not call for retroactive application of the disallowance. [Louiselle Rej. Test. at 22].

Both Mr. Beekman and Mr. Louiselle are off the mark. The Commission's authority to disallow overrecoveries in the fuel clause is not dependent on Order No. U-17282-H, nor can it turn on the absence of a disallowance in 1987. The authority to review fuel clause recoveries emanates from the Commission's plenary power to regulate rates. Reviewing past collections does not violate the rule against retroactive ratemaking because the company never obtained a binding regulatory approval of those costs for ratemaking. A review of the NISCO double recovery, for the entire period of Phase 1, is no different than the review of any other Phase 1 fuel recoveries insofar as retroactive ratemaking is concerned.

In 1990, when Order No. U-17282-H was issued, the Commission's authority to review past fuel clause overrecoveries was not settled in Louisiana. The issue was settled, however, in *Daily Advertiser v. Trans-La etc.*, 612 So. 2d 7 (La. 1993), which made it clear the Commission has authority to conduct this review. The Court determined that the allowance of monthly cost adjustments in the fuel clause does not preclude a subsequent examination of the propriety of the costs. It stated:

[T]he commission's allowance of monthly cost adjustments pursuant to such clauses does not constitute rate making in the traditional sense of that term because such adjustments go into effect without an antecedent reasonableness review and thus are not 'commission-made' rates. It follows then that the commission is not precluded by the rule against retroactive rate making from subsequently examining and modifying such adjustments.

***51** *Id.* at 23.

The Court concluded: '[A]utomatic fuel adjustment clauses are an integral part of the rate making process, are subject to ongoing commission regulation, and can be adjusted retroactively by the commission to require the utility to refund overcharges to its customers.' *Id.* at 26.

The fact that the NISCO double recovery was disallowed prospectively in March, 1990 does not in any way undercut the Commission's authority under the *Daily Advertiser* ruling. First, since *Daily Advertiser* had not been decided at that time, the Commission did not have clear authority to disallow costs previously incurred, and could not legitimately be deemed to have 'approved' the past overcollections. Second, the Commission's clear statement of principle - that the double recovery was unjustified - can only add to the propriety of a disallowance in this proceeding. It is ironic that **Gulf States** would try to use an Order condemning the double recovery as the basis to claim it was really approved for the period prior to March, 1990.

Nor can the Commission's inaction on a recommendation of Mr. Kollen in 1987 be relevant. Mr. Kollen's 1987 recommendation was made in a base rate proceeding. The Commission's failure to adopt it is not an 'approval' or 'disapproval' of any cost flowing through the fuel clause. Indeed, **Gulf States** raised this argument in the Supreme Court in the NISCO case as a basis for overruling the Commission's NISCO Order; the argument was not adopted. [*See* ***Gulf States*** *Utilities Co. v. Louisiana Public Service Com'n*, 633 So. 2d 1258 (La. 1994), Orig. Brief on Behalf of Appellee, **Gulf States** Utilities Co. at 30-31 (No. CA 1185)]. Further, the 1987 Order - which did not address the question - was issued almost a year *prior* to the beginning of the period covered by Phase 1. At that time, none of the Phase 1 costs had yet been incurred. Thus, the 1987 Order could not have approved them.

Additionally, ignoring the pre-March, 1990 period would be a disservice to ratepayers. This Commission has held that the double recovery of the NISCO costs was never approved and was an unjustified recovery. The Supreme Court has now ruled that the original Order disallowing NISCO costs was appropriate 'for the promotion of the public good.' ***Gulf States** Utilities Co. v. Louisiana Public Service Com'n*, 633 So. 2d 1258, 1265 (La. 1994). As the concurring justice stated, there is an 'inequity [in] making the ratepayers pay twice for the generating units,' which would provide the company 'an undeserved windfall at the ratepayers' expense.' *Id.* at 1267 (Dennis, J., concurring). Public policy requires that the Commission avert this inequity for all the Phase 1 period, not just the time subsequent to the district court's injunction.

The Commission will adopt Mr. Kollen's calculation of the refund amount, and adjust his calculation for consistency with the computation of the post-March, 1990 refund. With this adjustment the appropriate refund is about $5.22 million, consisting of $2.99 million of overcollections and $2.23 million of interest.

IV. NUCLEAR OUTAGES

[11][12][13][14] During Phase 1 **Gulf States** experienced several outages at River Bend that were the subject of disallowances by the Texas PUC. Pursuant to the agreement between **Gulf States** and the Staff, the record in the Texas fuel proceeding was used as the initial basis for examining the costs flowed through the fuel clause. Thus, Mr. Kollen focused on the Texas nuclear disallowances in determining whether similar disallowances should be made in Louisiana.

In its initial testimony, **Gulf States** did not address the determinations of the Texas Commission. Instead, it provided general testimony regarding the standard to be applied in evaluating River Bend's performance and compared River Bend with other generators. [Louiselle Dir. Test. at 2-7]. **Gulf States** did not offer expert nuclear testimony in its initial case.

Basing his recommendations primarily on documentation reviewed in the Texas proceeding, Mr. Kollen proposed four disallowances relating to River Bend: 1) an extension of Refueling Outage 2 of 11 days resulting from allegedly improper actions of Cooper Industries, a contractor; 2) an extension of Refueling Outage 2 of 16 days resulting from an explosion in the ***52** 'B Preferred Transformer'; 3) a two-day extension of Refueling Outage 3 resulting from a diesel generator fire; and 4) outages required to repair oil leaks resulting from installation of the wrong O-rings in certain locations. [Kollen Dir. Test at 10-19]. He recommended about $2 million of disallowances and a refund, including interest, of about $2.5 million. [Kollen Supp. Surr. Test. at 2].

Gulf States responded to Mr. Kollen's testimony by filing 'rebuttal' testimony that, for the first time, addressed the Texas disallowances. In addition, **Gulf States** put forth the theory that the outages did not cause any harm to ratepayers, because ratepayers assertedly are better off when River Bend does not run due to imprudence. According to GSU, the total cost flowed through the fuel clause for electricity from River Bend, including the 4.6 cents per kilowatt hour that **Gulf States** receives for the portion of River Bend designated a 'deregulated asset' in Order No. U-17282-H, exceeds the alternative incremental fuel cost of supplying the electricity. [Louiselle Reb. Test. at 6-9]. Thus, in effect, **Gulf States** contends that customers are better off whenever River Bend is down because of imprudence. [*Id.*].

Three issues must be resolved in connection with the nuclear outages: 1) the appropriate prudence standard to be applied to the outages; 2) whether the standard was satisfied; and 3) whether the outages caused a cognizable injury to ratepayers that should be remedied by the Commission.

A. Prudence Standard.

Bruce M. Louiselle, a **Gulf States** witness, proposed a two-tiered standard in his direct testimony for evaluating the prudence of River Bend's operation. His proposal was altered substantially, however, in subsequent testimony and cross-examination. The standard would change the Louisiana rule and will not be adopted. Additionally, the Commission will impute the imprudence of a utility's contractor to the utility, absent compelling reasons to do otherwise.

1. Two-Tiered Prudence 'Standard.'

Mr. Louiselle initially proposed a standard based on whether the utility's performance is above or below average. He asserted that the utility should be evaluated against 'well-accepted measures of performance.' [Louiselle Dir. Test. at 3]. He added:

If those results show that the performance was at or above average, or at or above some acceptable industry standard, the inquiry should be at an end. If those results show below average performance, further inquiry would then be appropriate.

[*Id.*].

Mr. Louiselle clarified the 'at an end' language in his testimony, proposing instead a standard requiring intentional misconduct for imprudence when a utility's performance is above average. He said no adjustment should be made if a utility's action that led to higher costs 'was inadvertent or simply human error.' [*Id.* at 4]. He enunciated the standard for a disallowance as follows:

Alternatively, were the decision or action to be the result of, say, a pattern of decision-making that was known to be incorrect or, an action that was not inadvertent but a conscious disregard for sound utility practice and an increase in fuel costs resulted therefrom, then an adjustment would be appropriate in my opinion.

[*Id.*].

Mr. Louiselle presented data comparing River Bend to certain other nuclear units and concluded the operation of River Bend was above average. [*Id.* at 5-7]. He stated: 'Absent a showing that an event caused by clearly imprudent action, not simply inadvertence or human error, caused an increase in fuel costs, the River Bend fuel costs are probably chargeable to customers. ' [*Id.* at 7].

In his rebuttal testimony, Mr. Louiselle apparently altered this standard. He addressed River Bend outages in which the actual outages exceeded the projected outages. One outage was extended by eight days, the average for Mr. Louiselle's comparison group, but the other was ***53** extended by 25 days, or more than the average. Mr. Louiselle testified that the River Bend outages should be deemed prudent because they fell within 'one standard deviation' of the average. [Louiselle Reb. Test. at 5]. He said:

First, to treat outages that exceed that projected as imprudent would mean that one-half of the outages were affected by imprudent actions or events. Second, both of the outages experienced by **Gulf States** fall within one standard deviation of the typical differential. Thus, these data do not support the conclusion that **Gulf States**' was imprudent.

[*Id.* at 5].

At the hearing Mr. Louiselle appeared to back away from the standard proposed in his direct testimony. He conceded that he would apply different tests to a utility's performance depending on whether it was above or below average. If above average, the utility's action could be deemed imprudent only if it were done with conscious disregard for the ratepayers' interests or an intent to cause the ratepayers harm. [Tr. 5/25/94 at 95]. If the utility's conduct were below average, it would be required to show that it acted reasonably in the circumstances. [*Id.*].

Mr. Louiselle argued, however, that this analysis reflected the application of a single standard rather than a two-pronged standard. [*Id.*]. He said: 'That is the application of the standard. It is not the definition of the standard nor is it two different standards.' [*Id.*]. Moreover, he expressed satisfaction with the prudence standard announced by the Louisiana Supreme court in ***Gulf States*** *Utilities Co. v. Louisiana Public Service Com'n*, 578 So. 2d 71, 85 (La. 1991), which makes no mention of different applications of the test. [Tr. 5/25/94 (Mr. Louiselle) at 91]. Further, he testified that 'conscious disregard' may include situations where a utility should have known, but did not know, of a better practice. [*Id.* at 86-88]. Additionally, Mr. Louiselle drew a distinction between 'human error' and 'simply human error,' but did not define the difference. [*Id.* at 91-92]. He testified that a utility should not be penalized for 'simply human error,' which he characterized as 'mistake or inadvertence or human error,' but that an imprudence disallowance could be based on 'human error.' [*Id.* at 91]. He testified there was 'no need' to clarify the difference between the terms. [*Id.* at 92].

Mr. Louiselle's testimony does not provide a basis for changing the application of the prudence standard in Louisiana - which requires the utility to perform in a reasonable fashion, whether the results are above or below average. In ***Gulf States***, where the Louisiana Supreme Court extensively discussed the prudence issue, the Court did not suggest that the prudence standard differs depending upon the utility's overall performance. *See* ***Gulf States*** *Utilities Co. v. Louisiana Public Serv. Com'n*, 578 So. 2d 71, 84-97 (La. 1991). In ***Gulf States***, the court explained the prudent investment standard as follows:

That standard 'essentially applies an analog of the common law negligence standard for determining whether to exclude value from rate base.' That is, the utility must demonstrate that it 'went through a reasonable decision making process to arrive at a course of action and, given the facts as they were or should have been know at the time, responded in a reasonable manner.'

Id. at 84-85 (citations omitted). When the Court analyzed **Gulf States'** investment using this standard, it did not first determine whether **Gulf States**' performance was above or below average. *See id.* at 84-97. Thus, the Court's analysis indicates that the utility's performance versus the average does not alter the application of the prudence standard.

Additionally, in a leading case, the Federal Energy Regulatory Commission expressly rejected the use of average performance in applying the prudence test. In *Kansas Gas & Electric Co.*, 39 F.E.R.C. ¶ 63,013 at 65,062-65,064 (F.E.R.C. April 24, 1987), Kansas Gas and Electric ('KG&E') presented evidence during the prudence review which showed that Wolf Creek was a well-managed nuclear project with a performance 'better than the industry average.' *Id.* However, the FERC held that ***54** exemplary performance in other areas would not excuse a utility's imprudent performance. It said:

The difficulty with KG&E's argument is that good performance does not excuse imprudent performance when FERC is conducting a prudence inquiry; prudent performance is always required. When, for example, KG&E paid money to Daniel for work not performed, rate payers should not have to reimburse KG&E for those payments nor give KG&E a return on those sums, however exemplary KG&E's performance in other areas. FERC is not a parole board granting time off for good behavior.

Id. at 65,064.

The Commission rejects the argument calling for different applications of the prudence test depending on whether the utility's overall performance is above or below average. **Gulf States** had an obligation to act reasonably in the circumstances, which requires that it take actions that reasonable utility executives would have taken given information available at the time. If it did not do so, the fact that its performance in other areas made its overall performance above average is not a basis for ignoring the imprudent conduct. Additionally, the prudence standard is evenhanded, requiring the *same* performance of the utility regardless of its comparability to the average performance level of others. Mr. Louiselle's standard is not consistent; it requires the utility to prove only reasonable performance if it is below average, but demands much stronger proof to support a disallowance if the utility's performance is above average. This differential approach is unjustified.

Additionally, the application of Mr. Louiselle's test would promote disputes regarding the choice of appropriate comparable groups and other factors. In this case Mr. Louiselle relied on a comparable group provided him by **Gulf States** to determine capacity and availability factors. The company reportedly supplied a group selected by a member of the Texas Public Utility Commission Staff in a prior proceeding. Mr. Louiselle did not know the name of this Staff member and relied on hearsay concerning the criteria the staff member employed in making his selection. [Tr. 5/25/94 at 100-02]. Mr. Louiselle testified that he made no study of his own to determine whether the selection criteria were appropriate. [*Id.* at 102-03]. In making his outage comparison, Mr. Louiselle used data provided by Entergy for a different period than that being reviewed in this proceeding. [*Id.* at 105-06]. He then applied a 'within one standard deviation' test rather than an above/below average test. [Louiselle Reb. Test. at 5]. The selection processes and other criteria used by Mr. Louiselle could easily be disputed and likely would not produce an improved application of the prudence test.

The evenhanded standard announced in ***Gulf States*** will be used by the Commission. Distinctions should not be drawn based on above or below average overall performance or number of standard deviations the utility's performance falls from the average. The utility is required to act reasonably in all its decisionmaking.

2. Contractor Imprudence.

A related prudence issue is whether the utility may be held responsible for the actions of its contractors. Mr. Kollen testified that **Gulf States** should be held responsible for the actions of its contractors as if it had performed the work itself. He said:

From a regulatory perspective, GSU is as responsible for the actions of its contractors as if it had performed or failed to perform the work itself. GSU is responsible for the adequate supervision and review of contractor work activities and performance.

[Kollen Dir. Test. at 13].

Gulf States offered no testimony in opposition to this contention.

Although many cases are unclear on the extent to which contractor activities may be imputed to the utility, the best-reasoned view is set forth in a decision of the Pennsylvania Supreme Court. ***55** Pennsylvania Public Util. Com'n v. Philadelphia Electric Co., 522 Pa. 338, 561 A. 2d 1224 (1989). In *Philadelphia Electric,* the Court held that replacement power costs incurred by the utility when its nuclear power plant shut down as a result of a defect in a component part manufactured by the utility's contractor could not be passed on to the consumers. The Court noted that Philadelphia Electric did not contribute to the manufacturing of the defective resins which caused the shutdown. However, the Court concluded that Philadelphia Electric was still responsible for the outage. The Pennsylvania Supreme Court based its conclusion on the following policy considerations:

[W]e believe a utility company is in a better position to prevent an occurrence or provide for protection against any such occurrence. After all, it was the utility which chose the contractor, negotiated the contract and is in a position to seek damages for any losses sustained under the contract. While the utility may have to bear the initial losses incurred as the result of its contractor's negligence, it is in a far better position to aggressively pursue the tort-feasor for reimbursement. If we were to hold otherwise, the utility would have no incentive to pursue the tort-feasor, having already received full compensation for its losses. On the other hand, ratepayers would not be in a position either legally or financially to pursue the alleged tort-feasor.

[*Id.* at 346-47, 1228.]

See also Pennsylvania Power Co. v. Pennsylvania Public Util. Comm'n, 155 Pa. Cmwlth. 477, 625 A. 2d 719, 145 PUR4th 112 (1993).

The Commission finds that contractor negligence will be imputed to the utility in determining prudence, absent unusual circumstances making this approach unjust. The real issue is who should pay for a loss caused by a contractor - the utility or its ratepayers. Ratepayers have absolutely no control over the contractor and should not be required to bear the loss. The utility is in the best position to control a contractor and pursue it for a remedy if a negligent loss occurs. The contractor works for the utility in much the same way as its employees, whose imprudent actions are automatically imputed to the company. Absent automatic imputation, the utility would have an incentive to use contractors even when they are not necessary and would have less incentive to manage contractors properly and pursue them for remedies. Further, if utility fault as well as contractor fault were required for a prudence disallowance, the evidentiary process in a prudence case could become even more cumbersome and complex than already is the case. Therefore, automatic imputation will be the rule.

B. River Bend Outages.

River Bend, like other nuclear power plants, must schedule outages to replace spent fuel. During refueling outages, the utility conducts maintenance, inspections and testing that cannot safely be performed while the nuclear reactor is in operation. [Freehill Reb. Test. at 2]. Since it is planned and scheduled in advance, a refueling outage is considered a 'planned outage.' A 'forced outage' occurs when the unit shuts down automatically or manually in response to unplanned problems such as system failures, equipment failures, or incidents such as a fire or explosion.

When River Bend suffers an outage, **Gulf States**' customers must be supplied with electricity from other sources, either from less efficient facilities on the system or with power purchased from other utilities. Since the company's right to recover fuel and related costs is conditioned upon the costs being prudently incurred, the consultants reviewed River Bend's outage history for the 'review period.' Refueling Outage 2 ('RFO-2') and Refueling Outage 3 ('RFO-3') occurred during the review period. RFO-2 began on March 15, 1989 and ended on June 8, 1989, or 25 days more than the planned schedule. [Kollen Dir. Test. at 11]. RFO-3 began on September 29, 1990 and ended December 4, 1990, a total of eight days longer than the initially planned schedule. [Kollen Dir. Test. at 16]. In the Texas proceedings, the PUC limited **Gulf States**' fuel recovery for five forced or extensions of planned outages based on findings of imprudence. The PUC ***56** disallowed any recovery for the incremental fuel costs attributable to those 'forced' and/or extended outages.

The Commission staff reviewed extensive documentation from the Texas PUC proceedings, including the testimony of **Gulf States**' employees, the testimony of the experts retained by the various parties, the recommendations of the Hearing Examiner and the Order issued by the PUC. Further data requests directed to the company led to the production of additional information. The Commission's consultant, Mr. Kollen, concluded that the evidence supported the Texas PUC determination that imprudence caused the following outages, and recommended that the attendant incremental fuel costs be disallowed:

	Outage	Delay	TPUC Disallowance Total System	*Mr. Kollen's* Recommended Louisiana Retail Disallowance
1.	RFO-2 Delays Associated with Division I Diesel Generator Work by Cooper Industries	11 days	$1,584,012	$731,000
2.	RFO-2 Explosion of 'B' Preferred Transformer	16 days	$2,245,911	$1,037,000
3.	RFO-3 Division II Diesel Exhaust Fire	2 days	$343,000	$71,000
4.	Post RFO-2 EHC O-Ring Oil Leaks		$400,330	$185,000
	(a) June 24, 1989; and	8 hours		
	(b) June 29, 1989	56 hours		

Mr. Kollen did not recommend that the Commission adopt other Texas PUC disallowances.

When the Commission raises serious doubt about the prudence of a particular action, the burden shifts to the utility to prove that the action was prudent or resulted in no additional cost. **Gulf States** Utilities Co. v. Louisiana Public Service Com'n, 578 So. 2d 71, 85 (La. 1991). The findings of the Texas PUC and the analysis of Mr. Kollen raise serious doubt about the prudence of **Gulf States** in connection with these outages. Although **Gulf States** was given the opportunity to address the issues in the Texas proceeding in direct testimony, it did not do so. Only after Mr. Kollen filed his testimony did GSU offer testimony of two employees, Donald Derbonne and Peter Freehill, to address specific outages.

The Commission finds that **Gulf States** was imprudent with regard to the RFO-2 Division I Diesel Generator Delays, the RFO-2 'B' Preferred Transformer explosion, the RFO-3 exhaust fire, and the Post RFO-2 EHC oil leaks, and denies GSU's recovery of the incremental costs for replacement fuel and power resulting from these outages. With respect to the RFO-2 'B' Transformer explosion, however, the Commission adopts Special Counsel's recommendation and orders only one-half the disallowance proposed by Mr. Kollen.

1. Critical path scheduling.

In planning a refueling outage, the River Bend outage managers establish a critical path ***57** schedule. The various departments identify the tasks that must be performed during the outage. [Freehill Depo., (3/24/94) at 33-36]. Since all tasks cannot be performed at the same time, and some tasks must be completed before others can be started, the outage management group must align the tasks in the sequence that will result in the completion of all of the tasks in the shortest time. [*Id.*] The 'critical path' then is the schedule of specific tasks that determines the potential duration of the outage. While other work items may be performed in parallel with the critical path items, the critical path items are those that must be completed before the next sequence or phase of necessary projects can be started. [Freehill Depo., (3/24/94) at 34-35]. As a result, if an item on the critical path takes longer to complete than planned, there may be an extension of the outage. If completion of a 'non-critical path' item is delayed, it can become the critical path by delaying activities on the critical path.

In generating the critical path schedule, GSU personnel manually adjust the schedule as they receive input from the various departments. Although the critical path schedule may be printed from a computer, GSU manually plans the sequencing and does not rely on computers to structure the most efficient adjustments when problems arise during an outage. [Freehill Depo., (3/24/94) at 38-39].

2. RFO-2 Division I diesel generator delays.

Cooper Industries contracted with **Gulf States** to perform inspection, maintenance and testing of the Division I and Division II diesel generators during RFO-2. The company's documentation attributed 11 days of delay in the critical path schedule to the Division I diesel generator work and more particularly, to the performance of Cooper. Mr. Kollen recommended that **Gulf States** be denied recovery of incremental fuel costs traceable to those 11 days of delay. Mr. Kollen's recommendation is accepted.

Mr. Kollen's recommendation was largely based on contemporaneous GSU documents, particularly the Outage History Report and a summary report on the contract performance history of Cooper Industries. In response, GSU presented the testimony of Mr. Peter Freehill. Mr. Freehill was the Outage Manager for River Bend during RFO-2 and RFO-3. [Freehill Depo. (3/24/94) at 24]. Mr. Freehill is not a licensed engineer, but had the task of planning RFO-2 and RFO-3. [*Id.* at 24]. Mr. Freehill suggested that Mr. Kollen focused on only one page of the pertinent GSU Outage History Report and failed to consider other documentation, primarily Condition Reports and Maintenance Work Orders pertaining to work performed on the diesel generators during the outage. Mr. Freehill contended that 10 of the 11 days of delay were caused not by Cooper Industries but instead, by unanticipated repairs to manifold bolts on the diesel generator. [Freehill Reb. Test. at 1-10]. When tested under cross-examination, however, Mr. Freehill neither undercut Mr. Kollen's analysis of GSU's contemporaneous documentation nor rule out GSU's responsibility for the delays in completing the diesel generator work.

In RFO-2, the inspection of the Division I diesel generator was to be followed by certain tests and then inspection of the Division II diesel generator. Because of safety requirements, the Division I and Division II generators could not be serviced at the same time. Cooper Industries contracted to perform the inspections, maintenance and testing of the diesel generators. Mr. Freehill had no part in selecting Cooper as a contractor, nor any part in training Cooper or other contractors as to the appropriate procedures to use at River Bend. [Freehill Depo., (3/24/94) at 49-50]. That responsibility fell to other GSU employees. Similarly, direct day-to-day, on-site supervision of contractors like Cooper was the responsibility of the GSU project managers. [Freehill Depo., (3/24/94) at 50-51, 93-94]. Mr. Freehill, the company's sole witness on this issue, denied having expertise over procedures for supervision of contractors on site. [*Id.* at 94].

Gulf States' records reflect that in the post-outage review in 1989, GSU's supervisory personnel traced 11 days of delay to Cooper Industries. At the completion of an outage, the Outage Management Department produces an Outage History Report. The report is based on ***58** input from the various departments involved in the outage. [Freehill Depo. (3/24/94) at 72]. Drafts of the report are reviewed by Mr. Freehill and the final report is a product of Mr. Freehill's department, and incorporates the input of all persons considered necessary contributors. [*Id.* at 72-73].

The RFO-2 Outage History Report included a chart that identified milestone activities and the variances from the planned schedule. [Kollen Dir. Test., Ex. (LK-2) at 13]. The report indicates that the Division I Diesel Generator inspection was to start on March 15 and finish on March 26. [*Id.*] The work started on time but did not finish until April 12. [*Id.*] The sole cause of that delay identified on the chart was: '[d]elay due to contractor's lack of familiarity with GSU procedures.' [*Id.*]. Other sections of the Outage History Report support that conclusion. Pages 3-4 of the Report note that the qualification of parts on site delayed the inspection of the generator. [*Id.* at 3-4]. Page 9 of the report **states** that delays occurred due to 'spare parts qualification, [Quality Assurance] documentation, tagging, and [certain repairs including replacement of intake manifolds.']. [*Id.* at p. 9]. Mr. Freehill acknowledged that Cooper's spare parts qualification, quality assurance documentation and tagging performances all were subjects of complaint by GSU personnel. [Freehill Depo., (3/24/94) at 152-154]. Cooper was even forced to bring in a new project manager as a result of poor performance by the first project manager. [Kollen Dir. Test., Ex. (LK-2) at 9; Freehill Depo. (3/24/94) at 155-156].

In addition to the Outage History Report, GSU produced a 'Summary and Recommendation' for the closeout of the work performed by Cooper Industries. [Kollen Dir. Test. Ex. (LK-3)]. The Report noted:

The Cooper site management and planning effort started late and caused a 'never on time' ripple effect throughout most of the outage. Cooper had two other outages in progress when the RBS outage started which may have contributed to Cooper's staffing and management support problems.

[*Id.* at 4].

This report bears the signatures of several personnel responsible for overseeing the performance of contractors at River Bend.

Mr. Freehill acknowledged Cooper's poor performance but attempted to blame 10 days of the delay on the repair of manifold bolts on the Division I generator and the replacement of an angle brace. [Freehill Reb. Test. at 1-10; Rej. Test. at 1-4]. The documents do not support that conclusion. Mr. Freehill asserted that the Outage Meeting Agenda Report for April 11, 1989 indicates that the repair and replacement of the manifold bolts and bracing were the last items to be completed before starting the next critical path work - the ECCS testing. [Freehill Reb. Test. at 8-10; Att. PEF #2 to Freehill Reb. Test.]. However, other work was also going on while the manifold bolts and bracing were being repaired. Page 5 of the Agenda Report reflects the status on April 8, 1989. It projected that completion of the bolts and manifold bracing would be last before the start of the ECCS tests, but also shows that as of April 8, there were other work items on the diesel generator that were projected to remain incomplete until 5 p.m. on April 9. [Freehill Depo., (3/24/94) at 99-104].

Further, Mr. Freehill was unable to explain the delays in completing the repair of the manifold bolts and bracing. The Division I generator inspection commenced on schedule on March 15, 1989. The broken and missing manifold bolts were documented by GSU on March 18, 1989. [Condition Report 'CR' 89-0220, Att. PEF #1 to Freehill Reb. Test.]. Yet, work on the repair was not authorized until March 31, 1989 and was not completed until April 12, 1989. [MWO-0124492; Att. PEF #5 to Freehill Rej. Test.; Freehill Depo., (5/12/94) at 31-33]. These delays were unjustified because the diesel generator was critical path work, which **Gulf States** was supposed to perform around the clock. [Freehill Depo. (3/24/94) at 45]. The late completion is attributable to delays caused by Cooper Industries and slow turnaround by GSU.

The delays in starting bolt replacement and repair are traceable to Cooper Industries and GSU. The initial delay was caused by Cooper. Mr. Freehill reported that the bolt repair could ***59** not start until the inspection of the diesel cylinders was complete. [Freehill Rej. Test. at 3-4]. Since the diesel inspection was scheduled for completion on March 26, and work on the bolts did not commence until March 31 or April 1, inspection work was delayed at least five days. Also, as discussed above, additional inspection work was still outstanding on April 8. The bolt repair consumed 12 days; Mr. Freehill was unable to explain why the replacement and repair of the bolts consumed 12 days.[FN1] Thus, GSU has not met its burden of demonstrating that the cause of the delay was not attributable to GSU or its contractor. GSU should be denied the right to collect the incremental fuel costs associated with the 11 day extension of RFO-2.

GSU produced in response to PSC Seventh Data Requests the Outage Critique for RFO-2. This memorandum was distributed October 5, 1989 by Mr. Freehill and incorporated the suggestions submitted by the various River Bend departments. The Critique lists the following 'Action Required' items:

[31] Full time planners are needed in OM [Outage Management] to plan MWOs [Maintenance Work Orders] for forced outages and refueling packages. Packages should be prepared for contractors and parts identified and ordered, tagouts prepared and coordinated earlier for more effective L-III schedules.

* * *

[80] Award contracts early enough for key contractor personnel to be on site to learn specific paper work and paper flow, statusing, methods, and to become familiar with the GSU system.

[81] Have a GSU person with each contractor shift to coordinate work.

* * *

[127] Contractor planners were not trained to GSU procedures. Required reading is not sufficient. GSU should develop a short program of indoctrination for this.

These internal critiques identify some of the very types of problems associated with the work of Cooper. GSU personnel acknowledged that GSU did not have a program that adequately prepared contractors and the company for efficient joint operations during outages. GSU, not its ratepayers, was in the position to prevent and minimize the delays.

3. Diesel exhaust fire during RFO-3:

RFO-3 commenced on September 29, 1990 and ended December 4, 1990. The schedule was extended from 58 to 66 days. [Kollen Dir. Test. at 16]. Mr. Kollen recommended that GSU be denied recovery of incremental fuel costs for *two days* of delay traceable to an October 20, 1990 fire in the Division II Diesel Generator exhaust system. [Kollen Dir. Test. at 16-17]. GSU's Condition Report indicates that the fire occurred because flammable paper backing on the exhaust expansion joint insulation was ignited by hot exhaust gas 'blow by' from the generator. [Kollen Dir. Test. Ex. (LK-6) at 4]. GSU's documentation acknowledged that the 'exhaust blow by feature of the expansion joint was not considered in the selection of jacketing materials.' [*Id.* at p. 3 of 15]. Once the fire occurred, two days were lost in examining the cause and extent of the damage.

GSU offered no testimony to contest Mr. Kollen's recommended finding of imprudence. Instead, GSU offered testimony by Mr. Freehill who said that GSU made up the two day delay by *subsequent* scheduling adjustments. In particular, Mr. Freehill cites the RFO-3 Outage History Report, noting that before the Division II Diesel Generator work started, **Gulf States** was 1.5 days behind schedule and finished 12 days behind schedule with 2 days attributable to the exhaust fire. [Freehill Reb. Test. at 10; Att. PEF #4 to Freehill Reb. Test.]. He contends that after the fire, work schedules for other projects were changed so that by November 18, 1990, the schedule was again 1.5 days behind schedule. [*Id.* at pp. 10-11, citing Att. PEF #4 to Freehill Reb. Test. (page 28 of 94)]. Mr. Freehill's analysis does not withstand scrutiny.

Mr. Freehill's analysis assumes that getting back close to the original schedule automatically ***60** means there is no loss. That assumption is only true ff the original schedule was itself a good schedule. Mr. Freehill's testimony under cross-examination demonstrates that the post-fire return to within 1.5 days of the schedule resulted from a combination of (a) work taking less time to complete than initially planned and (b) readjusting some work from sequential to parallel performance schedules. These adjusted schedules did not involve work traceable to the fire and could have been scheduled for parallel performance under the original schedule. Mr. Freehill confirmed that the company could have originally scheduled the activities in parallel. [Freehill Depo. (5/15/94) at 82-94].

Between October 28, 1990-November 20, 1990, River Bend went from 12 days behind schedule to 1.5 days behind schedule. The catch-up was accomplished by working more efficiently than expected and by rescheduling tasks to be performed in parallel, instead of sequentially, with no decrease in safety. Clearly, the original schedule included substantial slack. If there had been no fire, the adjustments that led to a shortening of the Division I RPV and ECCS work could have started two days earlier and the outage would have been two days shorter. [*See* Freehill Depo., (5/12/94) at 98-104]. GSU's ratepayers should not have to bear the incremental cost of that extra two days.

4. Post RFO-2 - O-Ring leaks

GSU contracted with General Electric ('GE') to inspect and maintain the Electro-Hydraulic Control ('EHC') system during RFO-2. Among other tasks, GE replaced the O-rings in the EHC system. On June 24, 1989, a leak developed in one of the O-ring seals in the EHC system, resulting in an outage of approximately eight hours. On June 29, 1989, a second leak occurred in another O-ring seal, resulting in a 56 hour forced outage. **Gulf States**' records state that the installation of standard O-rings in valves for which the specifications require special 'Ultra-seal' O-rings caused the leaks. Both outages would have been avoided had GE accurately followed the specifications. Additionally, the second outage would have been avoided had GSU personnel taken the time to replace the other standard O-rings with the 'Ultra-seal' O-rings on the occasion of the first outage.

The EHC system has 4 control valves, each with 2 connections that require the 'Ultra-seal' O-rings. [Tr. 5/24/94 (Mr. Derbonne) at 110]. Both the June 24 and June 29 outages resulted from leaks in these valves. Shortly after the outages, GSU personnel undertook to determine the cause of the failures and identify appropriate steps to avoid a reoccurrence. GSU produced a Condition Report ('CR ') 89-0849 and Quality Assurance Surveillance Report No. 06-89-09-25. [Kollen Dir. Test. Exs. LK-7, LK-8]. The CR 89-0849 was prepared by Mr. Engle and reviewed by his supervisor, Mr. Langley. Both men were employed in the GSU system engineering department. [Tr. 5/24/94 (Mr. Derbonne) at 121-22]. Mr. Derbonne testified that when a CR report is issued, it reflects the concurrent findings of both the author and the supervisor. [*Id.* at p. 122]. Here, the two system engineers concurred that both outages resulted from the installation of the standard O-rings instead of the 'Ultra-seal' O-ring. [LPSC

Staff Exh. 10 at p. 3]. They also concurred that the root cause was the failure of GE to follow contractually required procedures, with GSU documentation a possible contributing cause. The report **states** in pertinent part:

The application of the correct part remains the first responsibility of the maintenance craft. *The failure to apply the proper Ultra-seal o-ring could have been avoided had reference to the appropriate site documentation been performed*. GSU craft and contract personnel are required to assure that proper parts are installed. The contractor was further required by contract to ensure that documentation exists to support the application of the replacement part. See page 6 for a contract excerpt on this subject.

While the existing documentation is sufficient, it is complicated by the lack of clear, readily accessible paper trail to the proper replacement part. A study of the supporting documentation and corrective actions necessary to improve the documentation base shall be undertaken as a further action to prevent this reoccurrence.

***61** [*Id*. at 4. (Emphasis added)].

The GSU/GE contract specifically required that when replacing spare parts such as O-rings,

Contractor shall ensure that identification of the replacement item is based upon current, approved GSU drawings, manuals, or written engineering concurrence, rather than on a •like-for-like' basis.

[*Id*. at p. 6].

The GSU Quality Assurance Department also investigated the outages. [LPSC Staff Ex. 11]. The quality assurance staff concurred that GE should have followed plans and specifications. The QA department recommended a review and improvement of the documentation and further recommended tagging the valves to alert people to the need for the non-standard 'Ultra-seal' O-ring. [*Id*.] Obviously, GSU could have helped to prevent the error by taking these precautions *before* GE began its work.

Having failed to prevent the installation of the incorrect O-rings, GSU personnel also failed to take steps that would have prevented the second forced outage of June 29, 1994. The GSU Condition Report describes the two outages as follows:

This problem is similar to a previous problem experienced on the Turbine/ Generator restart of 6/24/89.

In both incidences the electro-hydraulic [sic] fluid (EHC) leak from a Reactor Protection Switch (RPS) forced a turbine shutdown. The leaks were traced to a failed o-ring on a 1/4' Ultra-seal o-ring.

On 6/24, the standard o-ring found leaking was on one end of a 1/4' SS line connecting 1C71*PSN005C to the EHC dump valve on the #3 control valve. This line was two Ultra-seal fittings and *it was observed that both fittings used a standard o-ring*. The proper Ultra-seal #4 o-ring was re-installed on both ends and the system was returned to service. See PMWO R56360 for further information.

On 6/29, another o-ring was found leaking on the line connecting 1C71*PSN005B to the EHC dump valve on the #2 control valve. Again the leak was the result of a failed standard o-ring. Further investigation into the remaining two control valves showed the application of standard o-rings in the Ultra-seal fittings. Of 6 connections, 3 connections had the required Ultra-seal o-ring and 3 had a standard o-ring. All of these Ultra-seal fittings were renewed with the proper Ultra-seal o-ring. See PMWO's R 056325, 6 & 8.

[LPSC Staff Ex. 10 at 3. (Emphasis added.)]

Thus, on the occasion of the first outage 'it was observed' that incorrect fittings had been installed by

GE. Instead of investigating to see whether GE had failed to use the correct fittings in the remaining control valves, GSU simply replaced only the two incorrect O-rings on the then leaking valve and restarted the system. Knowing that all of the O-rings had been replaced by GE, and finding that both connections on the leaking valve contained incorrect O-rings, GSU should have been alerted that GE may have failed to install the correct O-rings in the other valves. Using two maintenance teams, the fittings could have all been replaced in the space of approximately three hours. [Tr. 5/25/94 (Mr. Derbonne) at 67-68]. The original outage might have been extended slightly, but the 56-hour outage of June 29, 1989 would have been avoided entirely.

The only testimony presented by GSU in opposition to the disallowances was that of Mr. Donald Derbonne. At the time of the outages, Mr. Derbonne was the Assistant Plant Manager, Maintenance. Mr. Derbonne offered his opinions and assumptions about the manner in which GE personnel installed the wrong O-rings and why GSU personnel did not investigate and cure the problem during the June 24, 1989 outage. However, Mr. Derbonne lacked firsthand knowledge, contradicted GSU's contemporaneous records, contradicted admissions in the Texas PUC proceeding by Mr. Philip Graham, the former River Bend plant manager, and at times contradicted his own sworn testimony.

Mr. Derbonne also opined that the failure to identify and install the correct O-ring was the ***62** result of 'human error,' not 'imprudence.' Mr. Derbonne essentially suggested that because GE installed 'Ultra-seal' O-rings in some of the valves, they must have been trying to do the right thing and GE and GSU should be excused for the loss. [*See* Derbonne Rej. Test. at 3]. Conversely though, Mr. Derbonne contends that GSU's documentation was adequate to inform GE as to the correct fittings, that the specifications were available, and that GE should have been able to follow the plans and specifications. [Tr. 5/24/94 (Mr. Derbonne) at 129]. Mr. Derbonne resolved this apparent contradiction by reading negligence/or carelessness out of his definition of imprudence. His standard for imprudence requires 'some conscious knowledge that you're doing something wrong.' [Tr. 5/24/94 (Mr. Derbonne) at 117]. This standard, also proposed by Mr. Louiselle, is inappropriate for judging the utility's conduct. [*See* § IV (A)].

5. Explosion of 'B' Preferred Transformer

In March of 1989, the 'A' Preferred Transformer ('A transformer') was taken out of service when tests indicated that low-side or through-faults had damaged the transformer. A new transformer was obtained while the original 'A' transformer was taken off-site, and repaired. In May, 1989, during RFO-2, through-faults occurred on the 'B' Preferred Transformer ('B transformer'). On May 29, 1989, the 'B' transformer exploded when it suffered its third fault in 28 days, resulting in a 16 day outage while a replacement was located and installed. Mr. Kollen recommended disallowing GSU's recovery of the incremental fuel/power costs associated with this 16 day outage. [Kollen Dir. Test. at 13-16]. The Commission will adopt Special Counsel's recommendation that **Gulf States** Utilities be denied one-half the incremental cost of replacement energy for the 16 day outage because GSU failed to take steps that would have prevented the explosion of the 'B' Preferred Transformer or to plan for a reserve to promptly replace the 'B' transformer when it failed.

The River Bend plant used the 'A' transformer and the 'B' transformer to provide power during start-ups of the nuclear plant. Neither of the transformers were used in day-to-day plant operations. [Tr. 5/24/94 (Mr. Derbonne) at 86]. The 'A' and 'B' transformers each receive 230 kv's of electricity from an off-site power source. Each of the transformers downstep the 230 kv to 13.8 kv and run the power on a bus to serve multiple pieces of equipment. [*Id.* at 84-85; *see also* LPSC Staff Exh. 4]. GSU attempted to keep the loads on both transformers fairly equal. [*Id.*] The 'A' and 'B' transformers were physically identical; they had the same size and capacity and carried the same electrical loads. [*Id.* at 84]. Although the auxiliary boiler was generally connected to the 'A' transformer, the load and service provided by the 'A' and 'B' transformers was not substantially different. [*Id.* at 85].

River Bend does not maintain on-site expertise in the maintenance of large transformers like the 'A' and 'B' transformers. The system engineers supervise basic preventive maintenance and smaller repair items. [*Id.* at 99]. When more substantial problems arose, GSU personnel in Beaumont or outside contractors analyzed the problems. [Tr. 5/24/94 (Mr. Derbonne) at 81-84].

In 1985, River Bend experienced problems with the 'A' transformer. [*Id.* at 87]. In a report dated September 20, 1985, W. J. Penner opined that the cause for the failure in 1985 was attributed to a number of low side faults on the system. [LPSC Staff Exh. 5]. Mr. Penner was one of the GSU specialists in Beaumont who evaluated problems with the large transformers. [Tr. 5/24/94 (Mr. Derbonne) at 84]. In March of 1989, the 'A' transformer again failed. After testing, GSU concluded that the damage was so extreme that the 'A' transformer was removed from service and a replacement transformer was ordered. [*Id.* at p. 89]. There is no evidence that the 'B' transformer was tested when the 'A' transformer was removed from service. [*Id.*]. Westinghouse Electric Corporation prepared a failure report on the 'A' transformer and attributed the cause to 'through-fault conditions.' [LPSC Staff Exhibit 6 at last page; Tr. 5/24/94 (Mr. Derbonne) at 93-94]. Mr. Penner evaluated the situation in an April 7, 1989 memo and similarly attributed the failure of the ***63** transformer to repeated through-faults. [LPSC Staff Exhibit 7; Tr. 5/24/94 (Mr. Derbonne) at 94-95].

On May 2, 1989, during RFO-2, and again on May 23, 1989, through-faults occurred on the 'B' transformer. On each occasion, the safety systems were tripped and the power shut down. Oil samples were taken and tested after each of these trips. A doble test performed by GSU after the May 2, 1989 trip was negative. The doble test is intended to determine if there is degradation of key components in the transformer that could cause a system failure. GSU elected not to perform a doble test after the May 23, 1989 trip. [Tr. 5/24/94 (Mr. Derbonne) at 90-93]. On May 29, the 'B' transformer again suffered a through-fault and exploded, literally blowing the top off the transformer. [*Id.* at 93].

A subsequent 'failure analysis' conducted by United Engineers and Constructors at the request of GSU, determined that the failure of the transformer resulted from 'through-faults or by use in feeding the auxiliary boiler.' [LPSC Staff Exhibit 8]. Similarly, GSU's Mr. Penner also opined that the explosion was caused by through-faults on the 'B' transformer. [LPSC Staff Exhibit 9].

The Texas PUC found imprudence of GSU in connection with the 'B' transformer explosion. Mr. Kollen similarly testified GSU was imprudent in failing to prevent the explosion following the repeated through-faults on the system. [Kollen Dir. Test. at 13-15; Kollen Surreb. Test. at 20-23].

In response to Mr. Kollen's testimony, GSU presented the testimony of Mr. Derbonne. Mr. Derbonne's testimony fails to meet GSU's burden of establishing prudence. GSU did not consider Mr. Derbonne an expert in the area of transformer troubleshooting and analysis. Oddly enough, neither Mr. Penner nor the systems engineers who did supervise the transformer testing and repairs were called by GSU. In addition, Mr. Derbonne offered no testimony on the reasonableness of the delays.

Mr. Derbonne acknowledged that neither he nor his department had involvement in analyzing the transformer problems in either 1985 or 1989. [Tr. 5/24/94 (Mr. Derbonne) at 82-83]. If any work other than general preventative maintenance was required on the transformers, GSU would rely upon experts outside the River Bend staff to analyze the problems. [*Id.* at 82-85]. Systems engineers had the primary responsibilities for the transformers on a day-to-day basis, but even those individuals did not report to Mr. Derbonne or his department. [*Id.* at 83-84].

When the 'A' transformer suffered problems in 1985, Mr. Penner was involved in the analysis of the problems. Mr. Derbonne was not asked to provide information regarding the possible causes for the problems. When Mr. Penner issued his memorandum in 1985, the information was furnished to the River Bend manager of quality assurance but neither distributed to nor discussed with Mr. Derbonne because it was outside his area of responsibility. [LPSC Staff Exhibit 5; Tr. 5/24/94 (Mr. Derbonne) at 87-89].

Similarly, when the 'A' transformer failed in 1989, Westinghouse performed a failure analysis and Mr. Penner again performed an analysis of causation and distributed a copy to the River Bend systems engineers. No copy was furnished to Mr. Derbonne. [LPSC Staff Exhs. 6 & 7; Tr. 5/24/94 (Mr. Derbonne) at 93-95]. Again, when the 'B' transformer suffered faults on May 2 and May 23, 1989, Mr. Derbonne's department was not asked to evaluate the faults.

Gulf States has failed to even address the reasonableness of the delays in resolving the problems and the resulting outage. The 'A' and 'B' transformers were used during start-ups. Other transformers serviced the busses during regular day to day operations. In March, 1989; the 'A' transformer was removed from service when testing showed damage to the 'A' transformer. The RFO-2 Outage History Report indicates that the 'A' transformer was sent off site for repair on April 1, 1989, but it was not until April 26, 1989 that orders were issued for the purchase of a spare transformer and for the installation of the replacement transformer. [Kollen Dir. Test., Ex. (LK-2) at 2 of 19]. The replacement/spare transformer was not installed and energized for testing until May 31, 1989, two days *after* the 'B' Preferred Transformer exploded, and two months after the 'A' transformer was first removed. Had GSU maintained ***64** a spare transformer, or had it acted more promptly to replace the 'A' transformer so that the 'A' transformer would have been available as a spare for the 'B' transformer, the outage would have been much shorter.

Gulf States' imprudent failure to respond quickly to the failure of the 'A' transformer or provide for the failure of the 'B' transformer unduly extended the outage for the 'B' transformer failure. Since there is no evidence establishing exactly how long the outage would have taken with adequate planning, the Commission disallows one-half the amount recommended by Mr. Kollen.

The conclusion in the Texas proceeding, coupled with Mr. Kollen's analysis, indicate that **Gulf States** should have anticipated a problem with the 'B' transformer after the failure of the 'A' transformer and the faults on the 'B' transformer. **Gulf States** failed to carry its burden of showing that it adequately planned for and anticipated potential problems with the 'B' transformer. The company did test the transformer, however, and assertedly determined that the transformer was in good condition. This action partially refutes the conclusion that **Gulf States** should have replaced the 'B' transformer immediately, especially since doing so would have caused an outage.

A better analysis should focus on the company's failure to develop adequate contingency plans for replacing the 'B' transformer after experiencing the failure of the 'A' transformer and the faults on the 'B' transformer. The company experienced undue delays in replacing the 'A' transformer. It had no backup equipment to replace the 'B' transformer when it failed. As a result, the outage took longer than necessary.

The Commission finds that **Gulf States**' imprudence caused one-half the delay resulting from the 'B' transformer explosion. This ruling adequately balances the competing considerations on this issue.

C. Impact of River Bend Outages.

[15][16] In opposing any disallowance for River Bend outages, **Gulf States** argued in its rebuttal testimony that the outages actually caused customers to be better off. According to Mr. Louiselle, because of the impact of the Commission's rate base exclusion plan for the portion of River Bend that was disallowed as imprudent, customers save money - at least in the short run - when imprudent conduct shuts down the unit. Therefore, **Gulf States** argues, imprudent outages should not lead to disallowances. [Louiselle Reb. Test. at 6-9].

Mr. Kollen calculated the cost of the outages based on the difference between River Bend's fuel cost and the cost of alternate generation. [Kollen Dir. Test. of at 10-19]. He initially made no separation of the 'regulated' and 'deregulated' portions of the River Bend plant. [*Id.*]. After considering **Gulf States**' arguments relating to the impact of the rate base exclusion plan, Mr. Kollen argued that the company should be penalized for only the added costs associated with the regulated portion of the unit after the plan went into effect. [Kollen Surreb. Test. at 7-11]. He disagreed that the added costs for imprudent conduct relating to the regulated plant should be offset by 'savings' in the payments required under the rate base exclusion plan. [*Id.*].

The rate base exclusion plan initially was proposed by the Commission as a potential settlement of litigation over the prudence disallowance. Order No. U-17282-D. **Gulf States** rejected the proposal, but the plan was imposed by the Nineteenth Judicial District Court in a decision that otherwise approved the Commission's prudence disallowance. The Commission complied with the district court's decision in Order U-17282-H, issued in March, 1990, but also appealed. The Louisiana Supreme Court subsequently overruled the district court's decision, holding that only the Commission had jurisdiction to determine in the first instance whether the plan should be adopted. ***Gulf States** Utilities Co. v. Louisiana Public Service Com'n*, 578 So. 2d 71, 97-101 (La. 1991). The Commission subsequently adopted a modified version of the plan. Order No. U-17282-K (La.P.S.C. February 12, 1992).

A common characteristic of the plans adopted in Order No. U-17282-H and Order No. U-17282-K is the provision that **Gulf States** may sell electricity from the deregulated asset ***65** to the regulated entity at a price of 4.6 cents per kilowatt hour ('kwh') if it is unable to sell the electricity at a higher price elsewhere. In effect, the ratepayers provide a guaranteed market for the output of the deregulated plant. The 4.6 cents per kwh charge is collected by the company through the fuel clause.

In theory, Mr. Louiselle's observation is correct that the combined effect of the 4.6 cents per kwh charge for electricity from the deregulated asset and the approximately one cent per kwh cost of fuel for the regulated portion of River Bend produced an average cost of electricity higher than the cost of fuel from alternate sources. The 'merged' fuel clause recovery for electricity from River Bend was about 2.6 cents per kwh, while the cost of fuel from alternate sources was about 1.8 cents per kwh. Thus, on a total fuel clause basis, customers did save money as the result of the company's imprudence. Nevertheless, Mr. Louiselle's approach improperly mixes the regulated and deregulated output of the unit.

The rate base exclusion plan is designed to accomplish the exclusion of the imprudent portion of River Bend from regulation, while permitting the company to realize some revenues for the asset and avoid a complete write-off of its investment. The plant was adopted as an accommodation to the company to ameliorate the impact of the River Bend disallowance. **Gulf States** is supposed to bear the risk, with respect to the deregulated asset, of events that prevent the generation of electricity. Under the sharing provisions adopted in Order No. U-17282-K, **Gulf States** has the option of selling electricity from the deregulated asset to any purchaser and keeping most of the proceeds. It also may sell the asset and retain most of the proceeds. The sharing percentages are subject to reconsideration by the Commission, but only after notice and a hearing. Order No. U-17282-K. If **Gulf States** fails to supply electricity at 4.6 cents per kwh as the result of an outage, even if the alternate cost of electricity is higher, it arguably would not be subject to an imprudence penalty.

Given the circumstances, counting fuel clause 'savings' for the rate base exclusion plan that result from an outage would not be appropriate. First, the deregulated asset is supposed to be separate from the portion of the unit that is considered in regulation. If the 'savings' from not running the deregulated asset should be considered now as an offset to higher costs caused in the regulated sector from imprudence, then in the future, when alternate costs are higher than the guaranteed payments, **Gulf States** should be subject to penalties when its imprudence reduces the amount of electricity available from the deregulated asset. It is doubtful that the company would agree to this application of a prudence standard to the deregulated asset, and the plan does not provide for it. Thus, adopting Mr. Louiselle's argument would serve the interests of the company in a one-sided way.

Second, mixing the excluded portion of River Bend with the regulated asset may send incorrect economic signals to the company. Mr. Louiselle's argument strongly suggests that the best thing to do with River Bend is to shut it down. Yet Mr. Louiselle also argues that it would be improper to conclude that River Bend should be shut down, because there would be long term costs of a shutdown not considered in his analysis. [Tr. 5/25/94 (Mr. Louiselle) at 111]. Until the Commission determines that River Bend is an uneconomic asset, it should apply regulatory principles that promote the use of the unit.

Third, the proposal of Mr. Louiselle is inconsistent with the method **Gulf States** previously used to calculate damages for a River Bend outage. In September, 1993, the company voluntarily agreed to make a refund for a River Bend outage, and calculated the amount based only on the higher costs attributable to the loss of electricity from the regulated portion of the unit. [Tr. 5/24/94 (Mr. Beekman) at 76]. This approach is consistent with that used by Mr. Kollen.

Fourth, three of the outages in this case occurred before the rate base exclusion plan was adopted.

Mr. Louiselle argued that the company's recovery for the deregulated asset is based on a rolling 36-month average electric output of the plant, which caused the outages to reduce the company's recovery for the deregulated asset even though they preceded the adoption of the plan. [Louiselle Rej. Test. at 7-10]. His observation is correct, but applying an offset***66** based on a plan that did not exist at the time to the outages - those prior to March, 1990 - would unduly stretch an already dubious concept.

The Commission will keep the regulated and deregulated portions of River Bend separate for the imprudence damage analysis. The company has not agreed, and presumably would not agree, to pay damages for imprudent outages of the deregulated asset in the future if those outages cost consumers money. Merging the shares at this time could thus produce a one-sided benefit to **Gulf States**. In view of the company's evidence, however, which clearly shows a short term harm from running River Bend, the Commission may consider whether the unit is economic in the long term. If not, the prudent decision may require a permanent shutdown of River Bend.

V. *SABINE PIPELINE 'HEADER' ISSUE*

[17][18] During the period under review, **Gulf States** included as fuel costs certain capital investments made for the benefit of **Gulf States** by Sabine Gas Transmission Co. and billed to the company as gas transmission costs. The investments were made for pipeline 'headers,' pipeline extensions and various other assets. **Gulf States** has the right to purchase the assets constructed for its benefit for a nominal sum, thought to be $1 by Mr. Beekman. [Tr. 5/24/94 (Mr. Beekman) at 43].

Gulf States should not have included the pipeline capital costs - even though nominally billed as 'transportation' - in its recoverable fuel costs. It had no authorization from the Commission to rebill the capital costs as fuel costs. Moreover, had the company made the capital investments itself, they would not have been recoverable through the fuel clause. [Tr. 5/24/94 (Mr. Beekman) at 45 (Mr. Beekman)]. The different form of the transaction, in which a separate company constructed the asset for **Gulf States** and included the costs in the cost of transporting gas, does not change the basic character of the expenditure. Capital costs are predictable, controllable expenses that should not be recovered through the fuel clause. Further, the recovery of the expenditures as fuel expense in this case prevented a proper matching of costs and service. Capital investments ordinarily are depreciated and recovered over time - usually years; the pipeline costs were assessed and recovered through the fuel clause over several months. [Tr. 5/24/94 (Mr. Beekman) at 50 (Mr. Beekman)]. Thus, certain ratepayers were unduly burdened with these expenses.

Allowing the recovery of capital investments made by a third party for the utility in the fuel clause would sanction the possible use of third party transactions as a device to avoid normal regulation. If the utility wishes to obtain recovery of a capital expenditure without an examination of all the other costs and revenues that affect base rates, it might enter contractual relationships with fuel suppliers to have the capital costs billed as fuel expenses. This approach would permit the utility to recover non-fuel costs without undergoing a full regulatory examination and would frustrate regulation.

Extending fuel clause treatment to capital additions made for the benefit of the utility also could lead to inefficient conduct. Mr. Louiselle explained at the hearing that fuel clause treatment of expenses tends to undermine utility incentives to bargain vigorously and may promote inefficient conduct. [Tr. 5/25/94 (Mr. Louiselle) at 116]. He said it also may lead to cost misallocations and could permit the utility to overrecover its costs. [*Id*. at 117].

The Commission will require a refund of the Sabine pipeline capital costs flowed through the fuel clause by the company. The refund, with interest, is $5,731,000. At the same time, in the upcoming base rate case, the Commission will permit the company to establish a regulatory asset for the pipeline assets in an amount equal to what the net book value of the assets would be in the test year after normal depreciation. Recovery of this net amount will be allowed over time as if it were in the rate base.

VI. *ADOPTION OF GUIDELINES AND REALIGNMENT OF COSTS*

After reviewing GSU fuel clause filings, Mr. Kollen noted that GSU includes in its fuel clause costs that would more appropriately be ***67** included in base rates. [Kollen Dir. Test. at 22]. GSU includes operation and maintenance costs that are not generation dependent, and investment costs such as depreciation, lease expense, and returns. [*Id.* at 22]. Mr. Kollen observed that there is no Louisiana statute or Commission order that clearly defines costs that are properly includable in the fuel clause. He asserted that there is a trend for utilities to circumvent the ratemaking process by including costs in the fuel clause when the utility would normally be required to wait for a base rate case to include the charges in rates. [*Id.* at 23-24]. Mr. Kollen noted that fuel clause charges are normally subject to less scrutiny than base rates, and that manipulation of the fuel clause enables the utility to grant itself a single issue rate increase. [*Id.* at 24].

Mr. Kollen recommended that the Commission adopt a general statement defining costs that are recoverable costs, and defining costs that should be excluded from the fuel clause. He suggested the following policy statement:

In general, only the direct cost of fuel delivered to the plant site and other fuel related costs that are directly dependent upon the level of electricity production or the energy cost of purchased power should be considered recoverable through the fuel clause. The fuel clause process should not be considered a supplement to or utilized by the utility to avoid the normal base ratemaking process for incremental base rate costs and without the full consideration of all revenue requirements issues.

[*Id.* at 24].

Mr. Kollen also recommended adoption of guidelines describing the specific costs that are includable and excludable from the fuel clause. [Kollen Surreb. Test. at 24-26]. He provided a description of includable and excludable fuel costs, and recommended that the Commission realign costs between base rates and the fuel clause during the post-merger GSU earnings review. [Kollen Direct Test. at 24-25; Kollen Surreb. Test. at 2, 24-26].

The company opposed the adoption of guidelines for fuel clause recovery, and disagreed with Mr. Kollen's definition of includable and excludable items. [Louiselle Reb. Test. at 9-12; Willis Reb. Test.]. Nonetheless, the company agreed that there are valid regulatory concerns regarding the kinds of costs that are included in an automatically adjusted fuel clause. [Tr. 5/25/94 (Mr. Louiselle) at 116].

Although Mr. Kollen provides compelling reasons to adopt guidelines and realignment, the Commission will defer adoption of guidelines regarding fuel clause recovery until the post-merger review of GSU. The Commission also plans to realign costs into base rates. The post-merger review of GSU is expected to be ready for a Commission decision late 1994 or early 1995. Since the Commission has the ability to retroactively adjust the fuel clause, this delay should not penalize ratepayers. Additionally, since adoption of general guidelines will necessarily have precedential effect on the fuel clause charges of other Louisiana utilities, deferment of a decision will allow input from other utilities.

VII. INTEREST ON CAJUN BUYBACK REFUND

[19] Mr. Kollen recommended that the Commission order GSU to refund interest associated with overrecovery that occurred through an accounting error associated with the River Bend Cajun buyback. The interest totaled $446,000 as of May 31, 1994. [Kollen Supp. Surreb. Test. at 2].

Mr. Kollen noted that review of the company's fuel clause filings indicated that certain non-fuel purchased power costs were apparently recovered twice by the company - through base rates and the fuel clause, and requested that the company provide further information. [Kollen Dir. Test. at 28-29]. The company provided an explanation of the accounting adjustment in the Rebuttal Testimony of Mr. Bobby Joe Willis. Apparently, in February, 1989, the company reviewed its prior fuel charge costs and discovered that it failed to recover non-fuel purchased power costs associated with the Sam Rayburn Nelson 6 buybacks. GSU also improperly recovered non-fuel operation***68** and maintenance expenses associated with the Cajun River Bend buybacks twice, once through base rates and again through the fuel clause. The two errors were partially offsetting, and the company refunded the net overrecovery. [Willis Rebut. Test. at 6; Kollen Surreb. Test. at 29].

Based on the company's explanation, and additional information provided in discovery, Mr. Kollen concluded that there was no double recovery of costs through the fuel clause and through base rates. Mr. Kollen found that the company computed the net overrecovery and refunded the overcollections caused by the partially offsetting errors over a prospective twelve month amortization period. [*Id.* at 29]. However, the company did not refund the amount that was overcollected *with interest*. Mr. Kollen recommended that the Commission order the company to refund the interest associated with the net overcollection. As Mr. Kollen explained, the net overrecovery was the result of multiple company errors. Since there was no interest factor in the fuel clause at the time, the company had the interest free use of the ratepayers' money for more than two years. [*Id.* at 30].

The overcollection was due to company errors. Although over and under recoveries in the fuel clause did not bear interest when the errors were made, the excess recovery for the Cajun buyback was not a typical overrecovery. Fuel clause over and underrecoveries occur merely from timing differences - costs are billed two months after they are incurred. These timing differences tend to offset each other over the year. A refund of an overcollection that results from a company error is a different matter and should bear interest, because the company's improper action deprived customers of the use of their funds. Thus, Mr. Kollen's recommendation is accepted.

VIII. CONCLUSION

The Commission adopts the fuel clause disallowances and the other recommendations contained in the report of Special Counsel. The fuel clause disallowances are:

	Principal	*Interest*	*Total*
I. NISCO			
A. Refund on remand	$10.6 mm	$3.1 mm	$13.7 mm
B. Prior double recovery	$2.99 mm	$2.23 mm	$5.22 mm
II. Nuclear Outages			
A. RFO-2 Cooper	$.731 mm	$.169 mm	$.9 mm
B. RFO-2 'B' Transformer	$.519 mm	$.120 mm	$.639 mm
C. O-ring leaks	$.185 mm	$.044 mm	$.229 mm
D. Diesel Exhaust Fire	$.071 mm	$.008 mm	$.079 mm
III. Cajun buyback interest		$.446	$.446
IV. Gas pipeline capital costs	$3.25 mm	$2.480 mm	$5.731 mm
TOTAL	*$18.347 mm*	*$8.597 mm*	*$26.944 mm*

These figures reflect interest through May 31, 1994. The actual interest refunded should run to the time of the refund. The company is ordered to refund $13.1 million of the $26.9 mm in its next billing cycle. The company may defer refunding the remaining portion of the $26.9 million pending further consideration at the Commission's August business meeting, if GSU files a motion for rehearing. If GSU chooses not to file a motion for rehearing, the remaining portion of the $27 million is to be refunded upon expiration of the time allowed for filing for rehearing. The Commission requires that the refunds be made through a one-time credit on customer bills, with a billing insert explaining the nature of the refund.

***69 Gulf States** is required to comply with the other requirements of this Order. Additionally, **Gulf States** is ordered to report to the Commission on the status of the Cajun-GSU coal cost litigation, as Mr. Kollen recommended. In Phase II, the Commission will determine the appropriate interest rate to apply to over and under recoveries in the fuel clause.

FOOTNOTE

FN1 Work was performed on an angle brace which attached to the generator. [Att. PEF

Re: Gulf States Utilities Company

Docket No. 10894

Texas Public Utility Commission

August 19, 1993

19 Tex. P.U.C. Bull. 1401, 1993 WL 655241 (Tex.P.U.C.)

PUR Slip Copy

Re Gulf States Utilities Company
Docket No. 10894

Texas Public Utility Commission
August 19, **1993**

Before Gee, chairman, Rabago and Greytok (all concurring and dissenting), Commissioners, and Bierman, administrative law judge.

BY THE COMMISSION:

***1** Commission disallowed $116,740,170 in fuel expenses incurred during fuel reconciliation period beginning October 1988 and ending September 1991. Second motions for rehearing denied by operation of law on October 3, **1993**.

[1] FUEL AND PURCHASED POWER - FUEL RECONCILIATION - SCOPE OF RECONCILIATION PERIOD/SCOPE OF REVIEW Absent evidence suggesting intentional wrongdoing by utility in booking fuel costs, prior period adjustment should be made during appropriate fuel reconciliation period, rather than outside such period. (Page 1421)

[2] FUEL AND PURCHASED POWER - FUEL RECONCILIATION - OTHER ISSUES Electric utility's shareholders, rather than its ratepayers, should bear expenses related to retaining load on system. (Page 1434)

[3] JURISDICTION - ISSUE AND CLAIM PRECLUSION - COLLATERAL ESTOPPEL Doctrine of collateral estoppel applies to relitigation of ultimate issues; it does not bar relitigation of issues merely because outcomes of two dockets may appear inconsistent. (Page 1435)

[4] FUEL AND PURCHASED POWER - FUEL RECONCILIATION - OTHER ISSUES Purchased power payments in excess of avoided costs should not be borne by Texas ratepayers, if payments exceeding avoided cost aim to retain utility's load in other state; under such circumstances, payments exceeding avoided cost should be shared between utility's shareholders and its ratepayers in other state. (Page 1443)

[5] FUEL AND PURCHASED POWER - FUEL RECONCILIATION - AFFILIATE TRANSACTIONS Expenses incurred by electric utility in purchasing fuel from joint venture in which utility has ownership interest must meet four-part test established in Railroad Commission v. Rio Grande Valley Gas Company, 683 S.W.2d 783 (Tex. App. - Austin 1984, no writ); load retention characteristics of joint venture have no bearing on issue of whether such four-part test applies. (Page 1448)

[6] Although first clause in definition of 'affiliate' in PURA § 3(i)(6) requires a finding of actual exercise of substantial influence or control over utility by affiliate, third clause in same definition only requires finding that affiliate and utility are under 'common control,' such control being the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of another. (Page 1451)

[7] Provision in joint venture agreement requiring unanimous consent of voting members on majority

of key management issues establishes affiliate relationship between utility and joint venture under 'common control' definition of 'affiliate' in PURA § 3(i)(6). (Page 1453)

[8] Provision in joint venture agreement that requires joint venture's participation in discussion and approval of expenditures for modifying utility's common facilities, for which joint venture is partially responsible, establishes affiliate relationship between utility and joint venture under 'common control' definition of 'affiliate' in PURA § 3(i)(6). (Page 1453)

[9] Although first part of four-part test in *Railroad Commission v. Rio Grande Valley Gas Company, 683 S.W.2d 783 (Tex. App. - Austin 1984, no writ)* cannot literally apply to transaction between utility and its supplying affiliate when latter does not supply power to any other entity, reasonableness of price supplying affiliate charges utility can be evaluated through market test which compares such price to (1) market price utility would pay in acquiring power in lieu of energy generated by affiliate, and (2) market price at which supplying affiliate would sell power if utility did not purchase all of its output. (Page 1455)

***2** [10] Determination of whether affiliate expense reasonably approximates actual cost of providing service to utility under *Railroad Commission v. Rio Grande Valley Gas Company, 683 S.W.2d 783 (Tex. App. - Austin 1984, no writ)* involves evaluation of actual expenses incurred, rather than consideration of any subjective 'value' not reflected in such expense. (Page 1455)

[11] In light of Texas Supreme Court opinion establishing utility's avoided cost as minimum floor of recoverable expenses, amount of payments to affiliate in excess of avoided cost should be excluded from utility's reconcilable fuel balance if utility fails to demonstrate that expenses incurred in purchasing power from affiliate are just and reasonable under PURA § 41(c)(1) and P.U.C. SUBST. R. 23.23(b)(2)(H)(iv). (Page 1456)

[12] FUEL AND PURCHASED POWER - FUEL RECONCILIATION - NUCLEAR FUEL In determining appropriate nuclear fuel disallowance related to imprudent outage of nuclear facility, interest payments on nuclear fuel, which accrue regardless of whether an outage occurs, must be included both in (1) calculation of actual expenses incurred during imprudent outage and (2) calculation of postulated expenses that would have occurred in absence of outage. (Page 1498)

[13] FUEL AND PURCHASED POWER - FUEL RECONCILIATION - OTHER ISSUES Revenue-related taxes and fees forwarded by utility to assessing governmental entities are components of utility's base rates and should not be disallowed in fuel reconciliation proceeding. (Page 1510)

[14] Exclusion of incentive rate-related fuel expenses from utility's total reconcilable fuel expense is proper because incentive ratepayers are not charged under utility's fixed fuel factor, but rather are assessed incremental cost of fuel at time power used; inclusion of such incremental expenses in total reconcilable fuel expense would result in allocation of an expense based on combined incremental and system average cost to both non-fixed fuel factor and fixed fuel factor customers, which would result in improper matching of fuel expense and fuel revenue for customers billed under fixed fuel factor. (Page 1512)

[15] FUEL AND PURCHASED POWER - FIXED FUEL FACTOR Utility's fuel factor should be developed using information related to proposed fuel year; Commission need not automatically adopt proposed fuel year, however, if deficiencies and/or inaccuracies undermine its adoption. (Page 1519)

[16] FUEL AND PURCHASED POWER - FUEL RECONCILIATION - GAS PURCHASES Utility's control over design, construction, and operation of gas transmission company's storage facility does not require utility to seek rate base treatment for transportation fees paid to gas transmission company. (Page 1528)

[17] Utility's accounting treatment of gas transmission company's storage facility as capital lease does not require utility to seek rate base treatment of transportation fees paid to gas transmission company, if such expenses are otherwise includible as fuel expense under Commission's application of fuel rule. (Page 1530)

***3** [18] FUEL AND PURCHASED POWER - FUEL RECONCILIATION - AFUDC ON FUEL Utility's request for classification of carrying costs on gas inventory as reconcilable, for purposes of their inclusion in future reconcilable fuel balance, is premature because (1) utility did not request recovery of such carrying costs in fuel factor calculation filed with its application; (2) such classification constitutes an advisory opinion because it is relevant only in utility's next fuel reconciliation proceeding, given that storage facility in question was not in operation during reconciliation period; and (3) such carrying costs are base rate costs. (Page 1533)

[19] FUEL AND PURCHASED POWER - FUEL RECONCILIATION - RATE CASE EXPENSES Utility cannot recover rate case expenses incurred by municipalities in fuel reconciliation proceeding through its fixed fuel factor. (Page 1552)

[20] PROCEDURE - PLEADINGS - FILING DEADLINES Pleadings addressed to Commissioners that are filed within 48-hour period specified in P.U.C. PROC. R. 22.71(h) [formerly P.U.C. PROC. R. 21.144] and do not fall within rule's exceptions are deemed not part of the record of the proceeding. (Page 1608)

[21] PROCEDURE - PREHEARING MATTERS - CONTINUANCE AND ABATEMENT Rather than second-guess federal district court on issue of whether utility is entitled to incremental coal pricing under joint agreement, Commission should defer ruling on all matters affecting such litigation and on any regulatory issues that might arise from matters emanating from such litigation until such litigation is concluded, whether by judicial order, settlement of parties, or another manner; regulatory treatment of any recovery by utility related to incremental coal pricing issue should be determined by Commission after litigation's conclusion. (Page 1670)

April 21, **1993**

TO: Marta Greytok, Commissioner Robert W. Gee, Chairman Karl R. Rabago, Commissioner All Parties of Record RE: Docket No. 10894 - Application of Gulf States Utilities Company to Reconcile Fuel Costs, Establish New Fixed Fuel Factors, and Recover its Under-Recovered Fuel Expense Dear Sir or Madam:

Enclosed is a copy of the Examiner's Report and proposed Final Order in the above-referenced docket. The Commission will consider this docket at an open meeting scheduled to begin at 9:00 a.m. on Wednesday, May 19, **1993**, at the Commission's offices, 7800 Shoal Creek Boulevard, Austin, Texas. Exceptions to the Examiner's Report must be filed in writing by 3:00 p.m., Wednesday, May 5, **1993**. Replies to exceptions must be filed in writing by 3:00 p.m. on Wednesday, May 12, **1993**. An original and seventeen (17) copies of exceptions and replies to exceptions must be filed with the Commission filing clerk and a copy must be served on all parties of record.

All parties should include all grounds, legal and factual, in the exceptions and replies, as appropriate, as there is no provision for subsequent rounds of pleadings, and late-filed material may not be considered. The parties are strongly urged to include an index with their exceptions and replies to exceptions. *ALL EXCEPTIONS AND REPLIES TO EXCEPTIONS SHALL FOLLOW THE SAME ORDER AS THE EXAMINER'S REPORT.*

***4** Pursuant to P.U.C. PROC. R. 21.143, requests for oral argument must be made in writing, filed with the Commission, and served on all parties by 3:00 p.m., Thursday, May 13, **1993**. Requests for oral argument *SHALL BE FILED AS SEPARATE PLEADINGS*, specifically entitled 'Request for Oral Argument.' If a request for oral argument is made, parties may call Ms. Cynthia Johnson at (512) 458-0266 after 9:00 a.m. the day before the final order meeting to learn if oral argument will be allowed by the Commissioners. If oral argument is allowed, the Commissioners may delay their decision until the following day. If a request for oral argument is not granted, the Commissioners may still have questions they want to address to the parties. Your presence at the final order meeting is not required, but you are welcome to attend if you so desire. A copy of the signed order will be mailed to you shortly after the final order meeting.

Upon written request, any interested party will be provided a packet of materials from the Hearings Division containing the written documentation of all communications between the Hearings Division and the Electric Division concerning calculation of the numbers in the Examiner's Report. Any challenges to the accuracy of the calculations in the Report shall be raised in the parties' written exceptions. Any alleged errors shall be specifically identified and alternative calculations provided to the extent possible.

Summary of ALJ's Recommendations

There is no statutory deadline for this docket.

Gulf States Utilities Company (GSU) filed an application on January 21, 1992, requesting reconciliation of its fuel and purchased power costs during the reconciliation period beginning October 1, 1988, through September 30, 1991, with the exception of: (1) the Nelson Industrial Steam Company (NISCO) purchased power expense, for which the beginning of the fuel reconciliation period is September 15, 1988; and (2) the Nelson Unit 6 rail transportation costs under contracts with Burlington Northern Railroad Company and Kansas City Southern Railway Company (the Railroads), for which the beginning of the fuel reconciliation period is December 1, 1986.

Including interest of $5,307,823, the total underrecovery calculated by GSU for the reconciliation period is $21,791,575. GSU requested a surcharge of the under-recovered amount, including interest, to be implemented over a twelve-month period. GSU also proposed new fixed fuel factors based upon a proposed fuel year of July 1, 1992, through June 30, **1993**.

The Office of Public Utility Counsel (OPC), Texas Industrial Energy Consumers (TIEC), the City of Beaumont, et al., the City of Calvert, et al., North Star Steel, and the General Counsel participated in this proceeding.

The General Counsel calculated an underrecovery of $20,088,443 and proposed new fixed fuel factors based on a calendar year **1993** fuel year. Based on its recommendations in this docket, OPC calculated an overrecovery of $29,389,101 for the reconciliation period. The two groups of intervenor cities calculated a combined recommended refund of $38,587,429.

***5** The principal issues in dispute concern GSU's requested reconciliation of its payments to NISCO. The primary analysis of the NISCO costs was developed under the test mandated by the Texas Supreme Court in *Public Utility Commission of Texas v. Gulf States Utilities Company*, 809 S.W.2d 201 (Tex. 1991). Other contested issues include the reconciliation of coal and nuclear fuel costs, GSU's payments to Sabine Gas Transmission Company (SGT), the appropriate fuel year, and the cities' requested reimbursement of litigation expenses.

For the reasons stated in the Report, the Administrative Law Judge's (ALJ's) recommendations result in an overrecovery, and resulting refund to GSU's customers, totalling $28,441,845 including interest as of September 30, 1991. The ALJ's recommended fixed fuel factor based on an adjusted calendar year **1993** fuel year is $0.018545/KWH. Sincerely, Beth Bierman Administrative Law Judge

DOCKET NO. 10894

ACRONYMS

ALJ	Administrative Law Judge
Anchor Darling	Anchor Darling Valve Company
BPGD	Butler, Porter, Gay & Day
CFB	Circulating Fluidized Bed
CFE	Comision Federal de Electricidad de Mexico
Citgo	Citgo Petroleum Company

CIV	Combined Intercept Valve
Conoco	Conoco, Inc.
Cooper	Cooper Industries
DOE	Department of Energy
DUCI	Diversified Utility Consultants, Inc.
ECCS	Emergency Core Cooling System
EEAR	Engineering Evaluation and Request
EHC	Electro-Hydraulic Control
EPE	El Paso Electric Company
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIT	Federal Income Tax
GDS	GDS Associates, Inc.
GE	General Electric Company
GSU	Gulf States Utilities Company
HL&P	Houston Lighting & Power Company
Industrial Participants	Citgo, Conoco and Vista
IRR	Internal Rate of Return
ISEG	Independent Safety Engineering Group
JOPOA	Joint Ownership Participation and Operating Agreement
KWH	Kilowatt Hour
LIS	Large Industrial Service
LLRT	Local Leak Rate Test
LPSC	Louisiana Public Service Commission
LSTG	Large Steam Turbine Generator
MMBtu	One Million British Thermal Units
MWH	Megawatt Hour
NERA	National Economic Research Associates, Inc.
NISCO	Nelson Industrial Steam Company
NRC	Nuclear Regulatory Commission
O&M	Operations & Maintenance
OPC	Office of Public Utility Counsel
PCRF	Purchased Cost Recovery Factor
PPA	Prior Period Adjustment
PUC	Public Utility Commission of Texas
PURA	Public Utility Regulatory Act
PURPA	Public Utility Regulatory Policy Act of 1978
QF	Qualifying Facility
RFI	Request for Information
RFO-2	Refueling Outage 2
RFO-3	Refueling Outage 3
River Bend	River Bend Station
RWCU	Reactor Water Cleanup System
SA	Special Analysis
SGT	Sabine Gas Transmission Company
SRMPA	Sam Rayburn Municipal Power Agency
Stone & Webster	Stone & Webster Corporation
SUS	Steam Users Service
TIEC	Texas Industrial Energy Consumers
Triton	Triton Coal Company
TUEC	Texas Utilities Electric Company
UEC	United Engineers & Constructors, Inc.
UTTCO	United Texas Transmission Company
Vista	Vista Chemical Company

EXAMINER'S REPORT

I. Summary

***6** Gulf States Utilities Company (GSU) requests the reconciliation of its fuel and purchased power costs during a reconciliation period beginning October 1, 1988, through September 30, 1991, with the exception of: (1) Nelson Industrial Steam Company (NISCO) purchased power expense, for which the beginning of the fuel reconciliation period is September 15, 1988; and (2) Nelson Unit 6 rail transportation costs under contracts with Burlington Northern Railroad Company and Kansas City Southern Railway Company (the Railroads), for which the beginning of the fuel reconciliation period is December 1, 1986.

GSU seeks to reconcile approximately $1,280,082,666 in coal, gas, oil, and nuclear fuel expenses incurred during the reconciliation period. The components of GSU's requested reconcilable fuel expenses are as follows:

Fuel	*Total Cost*
Coal	$ 189,880,434
Gas	931,355,216
Oil	625,046
Nuclear	158,221,970
	$1,280,082,666

As of September 30, 1991, GSU calculated a fuel underrecovery of $16,483,752, without interest. Including interest of $5,307,823, the total underrecovery calculated by GSU for the reconciliation period is $21,791,575. GSU has requested a surcharge of the under-recovered amount, including interest, to be implemented over a twelve-month period. GSU has also proposed new fixed fuel factors based upon a proposed fuel year of July 1, 1992, through June 30, **1993**.

Based on its recommendations, the Office of Public Utility Counsel (OPC) calculated an overrecovery of $29,389,101 as of September 30, 1991. The two groups of intervenor cities calculated a combined refund of $38,587,429 for the reconciliation period. The General Counsel, finding a total underrecovery of $20,088,443 including interest, recommended a surcharge.

The major issue in this case was GSU's requested reconciliation of its payments to NISCO. The analysis of the NISCO costs was developed under the test mandated by the Texas Supreme Court in Public Utility Commission of Texas v. Gulf States Utilities Company, 809 S.W.2d 201 (Tex. 1991). In addition to the NISCO issue, other major contested issues included the reconciliation of certain coal and nuclear fuel costs, GSU's payments to Sabine Gas Transmission Company (SGT), and the appropriate fuel year. Finally, the two groups of intervenor cities have requested litigation expenses for their participation in this docket. GSU has requested to treat the cities' reimbursed litigation expenses as reconcilable expenses to be flowed through the fuel factor established in this proceeding.

The Administrative Law Judge's (ALJ) recommendations in this case result in a $26,312,779 overrecovery without interest for the reconciliation period. Including interest of $2,129,066, the total overrecovery is $28,441,845. The ALJ's recommended fixed fuel factor is $0.018545/KWH.

II. Procedural History

On January 21, 1992, GSU filed its application initiating this fuel reconciliation docket. OPC, Texas Industrial Energy Consumers (TIEC), North Star Steel, the City of Beaumont, et al. (Beaumont), the City of Calvert, et al. (Calvert), and the General Counsel participated in the proceeding. The hearing convened on October 1, 1992, and was finally adjourned on November 6, 1992. There is no jurisdictional deadline in this case.

***7** Four attachments appended to this Report provide procedural information and other background information:

• Attachment A outlines the procedural history of this docket.

• Attachment B lists the counties in which GSU provides service and the newspapers in which GSU published notice of its application once each week for four consecutive weeks in compliance with P.U.C. PROC. R. 21.22(b)(4). GSU provided direct notice to its customers by bill insert and mailed notice to the mayors and city councils of the affected cities and to the county judges and commissioners of the affected counties.

• Attachment C lists the intervenor cities by intervention group.

• Attachment D identifies the parties and their representatives.

One matter of procedural import must be separately mentioned here. In an order issued on November 10, 1992, the Commission upheld Examiner's Order No. 37, which ruled on the confidentiality of certain documents in this proceeding. Under the terms of the protective order entered in this docket, any party who elected to challenge the Commission's decision in court had a period of ten days from the date of the Commission's order to appeal that decision. No appeal was filed.

Therefore, any exhibit admitted under seal in this proceeding and the portions of the transcript that were placed under seal by the ALJ are no longer entitled to protection from public disclosure *with two exceptions*: General Counsel Ex. 6B, Sch. BA-4 and Sch. BA-10. According to a letter filed by GSU on December 15, 1992, the confidentiality of these two schedules was preserved by agreement prior to the hearing on confidentiality conducted on October 1 and 2, 1992. All other exhibits or portions of the transcript placed under temporary seal are no longer treated as confidential.

III. Jurisdiction

GSU is a public utility as defined in § 3 of the Public Utility Regulatory Act (PURA), Tex. Rev. Civ. Stat. Ann. art. 1446c (Vernon Supp. **1993**). The Commission has jurisdiction in this proceeding pursuant to PURA §§ 16, 17(e), and 43(g).

IV. Legal Standards of Review and Burden of Proof

In a reconciliation of fuel costs, P.U.C. SUBST. R. 23.23(b)(2)(H) requires the utility to prove that:

• It has generated electricity efficiently;

• It has maintained effective cost controls;

• For all nonaffiliated fuel and fuel-related contracts, its contract negotiations have produced the lowest reasonable cost of fuel to ratepayers; and

• For all fuels acquired from or provided by affiliates of the utility, all fuel-related affiliate expenses are reasonable and necessary, and that the prices charged to the utility are no higher than prices charged by the supplying affiliate to its other affiliates or divisions or to unaffiliated persons or corporations for the same item or class of items.

P.U.C. SUBST. R. 23.23(b)(2)(H)(i)-(iv).

In deciding whether the utility has met these standards, the Commission has considered whether the utility acted prudently in incurring the costs. Prudence has been defined by the Commission as:

***8** The exercise of that judgment and the choosing of one of that select range of options which a reasonable utility manager would exercise or choose in the same or similar circumstances given the information or alternatives available at the point in time such judgment is exercised or option is chosen.[FN1]

The Commission has recognized that there may be more than one prudent option:

There may be more than one prudent option within the range available to a utility in any given context. Any choice within the select range of reasonable options is prudent, and the Commission should not substitute its judgment for that of the utility . The reasonableness of an action or decision must be judged in light of the circumstances, information, and available options existing at the time, without benefit of hindsight.[FN2]

The Commission has also held that an isolated error or failure to identify or correct an isolated problem can constitute imprudence. Whether it does or not depends upon whether the utility's conduct accords with the prudence standard stated above.[FN3] As discussed in Section V.C. of the Report, the Texas Supreme Court has established a test which GSU must meet in order to recover the NISCO costs which exceeded GSU's avoided cost.

V. Fuel Reconciliation

As of September 30, 1991, GSU claimed an underrecovery of $16,483,752. GSU Ex. 29A, Sch. FR.C-10 at 7. GSU's calculated interest on this underrecovery is $5,307,823, for a total underrecovery of $21,791,575. *Id.* at 14. Except for the issues discussed separately below and found adverse to GSU, the evidence demonstrates that GSU has met the requirements of P.U.C. SUBST. R. 23.23(b)(2)(H) concerning efficient generation, maintenance of effective cost controls, and procuring fuel at the lowest reasonable cost possible, and that all fuel-related affiliate expenses are reasonable and necessary. The ALJ finds, with the exception of the separately discussed issues found adverse to GSU, that GSU has met its burden of proof required by P.U.C. SUBST. R. 23.23(b)(2)(H) as to the reconcilable coal, gas, and nuclear costs incurred during the reconciliation period.

A. Natural Gas Costs

GSU's requested reconcilable natural gas cost for the reconciliation period is $931,355,216. The average cost of gas for the reconciliation period was $1.80/MMBtu. GSU Ex. 29A, Sch. FR.C-7 at 26.

1. Prior Period Adjustment (PPA) Applicable to United Texas Transmission Company (UTTCO) for the September 1991 Invoice Booked in October 1991

The booked cost of gas purchased from UTTCO during September 1991, the last month of the reconciliation period, was $3.14/MMBtu. GSU Ex. 19A, Sch. FR.C-7 at 23; GSU Ex. 30. GSU agrees that the cost of gas purchased from UTTCO during September 1991 was actually $1.7509/MMBtu. Tr. 525. Consequently, the booked cost of gas exceeded the actual cost by $434,262. GSU Ex. 30. GSU credited the $434,262 as a prior period adjustment (PPA) in October 1991 which would be addressed in GSU's next fuel reconciliation proceeding. GSU Ex. 31.

***9** Calvert argued that the adjustment to the UTTCO account should be made in this proceeding, suggesting that GSU may have misstated the cost of UTTCO gas to increase its cash flow in the last month of the reconciliation period. The ALJ finds no credible evidence to suggest that the UTTCO PPA was intended to increase cash flow.

In explaining the difference between the booked and actual cost of gas purchased from UTTCO in September 1991, GSU witness Mr. Harrington testified that at the time the UTTCO price was booked, UTTCO and GSU were negotiating a new contract. UTTCO sent GSU an invoice for $3.14/MMBtu, which was booked in September 1991. Tr. 529. This price reflected UTTCO's weighted average cost of gas plus an adder, in conformance with GSU's existing contract with UTTCO. Tr. 2859. When GSU received the invoice from UTTCO in October 1991 reflecting the actual cost of gas, GSU credited the account. [1] Mr. Willis, GSU's accounting witness, testified that PPAs are not unusual. In fact, if GSU had taken into account all of the PPAs for October 1991 and applied them to the September 1991 balance, GSU's underrecovery balance would have actually increased by $925,938. Tr. 795; GSU Ex. 31, 32 and 33. While there is no dispute that $3.14/MMBtu was the incorrect price, the ALJ recommends that the UTTCO PPA not be adjusted in this fuel reconciliation proceeding. Absent evidence which would suggest intentional wrongdoing, PPAs should be adjusted during the appropriate fuel reconciliation period and not outside that period, as urged by Calvert.

2. General Counsel's Recommended Disallowances Related to the Exxon Long-Term Gas Contract and the Rotherwood/Eastex Contracts

General Counsel witness Mr. Daniel Bivens recommended a disallowance of $122,108 on a total company basis related to GSU's purchase of gas under its Exxon and Rotherwood/Eastex contracts. His disallowance related to the Exxon contract is $118,256, while the remainder, $3,852, is related to the Rotherwood/Eastex contract. General Counsel Ex. 14A, Sch. DEB-9 Revised; Sch. DEB-11 Revised; Sch. DEB-13 Revised.

The proposed disallowances are based on Mr. Bivens' conclusion that GSU imprudently purchased gas in excess of the minimum take under these firm contracts. During the periods in which GSU exceeded the minimum take, cheaper gas was available on the spot market. General Counsel Ex. 14 at 17.

Mr. Bivens agreed that there may be times when spot gas is not available due to weather conditions, deliverability constraints, and mechanical problems in the delivery system. *Id.* at 16; GSU Ex. 22A, Sch. FR.E-5. In his review of GSU's monthly purchases, however, he determined that spot gas was available every month of the reconciliation period, and that in each instance in which GSU purchased gas above the minimum take from the firm supplier, cheaper spot gas was available.

The majority of the Exxon disallowance, $103,608, relates to GSU's take during the last six months of 1989. GSU's minimum take obligation under the Exxon contract is based on a daily average over a six-month period. If GSU does not take the minimum over that period, it has to pay a take-or-pay penalty. Therefore, to avoid the penalty, GSU must carefully plan its gas take over the six-month period. Tr. 2626.

***10** Going into December 1989, GSU had balanced its purchases under the contract such that, if it had taken the minimum obligation for the month of December 1989, GSU would not have incurred a take-or-pay penalty. Tr. 2630. GSU argued that it took more than the minimum take under the Exxon contract due to the unexpectedly harsh weather in December 1989. Mr. Bivens disagreed, arguing that there would have been more of a buffer available in December 1989 had GSU taken smaller amounts of gas under the contract during those months when spot gas was readily available. Tr. 2634-2635. He believed that the primary amount of overage during the last six months of 1989 occurred in July and August 1989, not in December 1989. Tr. 2624-2625.

Although the ALJ finds Mr. Bivens to be a very credible witness with respect to GSU's natural gas procurement activities and long-term gas contract administration,[FN4] she cannot recommend his disallowance. GSU reasonably balanced its takes under the Exxon contract for the six-month period until December 1989. It could not have foreseen the extreme harshness of the weather in late December 1989 and the resulting increase in demand.

GSU did not specifically rebut Mr. Bivens' recommended disallowance with respect to the Rotherwood/Eastex contract or his proposed disallowances for June 1989 and December 1990 under the Exxon contract. Instead, GSU focused on the Exxon disallowance during the last six months of 1989. Because GSU carries the burden of proof, the ALJ finds that GSU has failed to prove that Mr. Bivens' proposed disallowances with respect to the Rotherwood/Eastex contract and his proposed disallowance for the Exxon contract for June 1989 and December 1990 should not be adopted. This failure of proof results in a recommended disallowance of $18,500 on a total company basis.

B. Coal Costs

GSU is requesting reconciliation of $189,880,434 in coal costs for the reconciliation period. GSU Ex. 29A, Sch. FR.C-7 at 25.

1. Big Cajun II, Unit 3

Calvert witness Ms. Eileen Pitchford recommended three disallowances relating to GSU's inability to procure lower-priced incremental coal for its minority ownership in Big Cajun II, Unit 3. Because GSU failed to obtain reduced prices on incremental coal purchased in excess of the contract minimum or base volume, she contended that GSU used higher-priced Replacement B energy from Cajun Electric Power Cooperative, Inc. (Cajun Electric) and used higher-priced natural gas. Calvert Ex. 23B at 4. Her recommended disallowances are as follows:

1. GSU failed to procure and use incremental coal to displace natural gas:[FN5]

Total system	$ (2,442,220)
Texas only	(907,087)

2. GSU failed to procure and use incremental coal to displace Replacement B energy:[FN6]

Total system	$ (1,769,580)
Texas only	(662,780)

3. GSU failed to receive incremental pricing for coal above minimum:[FN7]

Total system	$ (355,410)
Texas only	(132,923)

***11** In the event the Commission did not accept her first recommendation listed above, Ms. Pitchford recommended a disallowance related to GSU's dispatch of its ownership share of the Cajun unit. Her recommendation regarding the utilization of Big Cajun II, Unit 3 is discussed in Section V.F. of the Report. Ms. Pitchford's recommended disallowance relating to the utilization of GSU's Sabine 5 is discussed in Section V.G. of the Report.

Big Cajun II consists of three 540 MW coal-fired generating units. Cajun Electric is the majority owner and operator at Big Cajun. GSU is a joint owner with a 42 percent undivided ownership interest (or 227 MW) in Big Cajun II, Unit 3. GSU's ownership interest in the plant common facilities is 14 percent. Calvert Ex. 23B at 8.

The coal supply for the unit is purchased by Cajun Electric under a coal supply contract with Triton Coal Company (Triton), a subsidiary of Shell Oil. The coal is transported to Big Cajun under transportation agreements between Cajun Electric and Burlington Northern and American Commercial Terminals, Inc., the barge transporter. GSU Ex. 19 at 9-10. GSU is allocated its portion of the coal expense incurred by Cajun Electric under the terms of the Joint Ownership Participation and Operating Agreement (JOPOA) for Big Cajun II, Unit 3 executed between GSU and Cajun Electric. Calvert Ex. 23B at 10.

Under the JOPOA, Cajun Electric has the authority and responsibility to manage all fossil fuel in accordance with Exhibit F to the JOPOA, The Fossil Fuel Management Plan. Calvert Ex. 27. The JOPOA precludes Cajun Electric from distinguishing between Unit 3, which it co-owns with GSU, and Units 1 and 2, which it owns outright. In other words, the fuel obtained by Cajun Electric must be equally available to the benefit of GSU. Calvert Ex. 23B at 11.

Just prior to the beginning of, and during, the reconciliation period, Cajun Electric negotiated with the coal supplier and transporters for incremental coal in excess of the minimum contract requirements to be purchased and delivered at reduced incremental prices. It is undisputed that Cajun Electric did not allow GSU to benefit from this lower-priced incremental coal. GSU agrees with Calvert that it should have benefitted *from the lower-priced incremental coal and that, as a result of its exclusion by Cajun* Electric, GSU's ratepayers will pay higher coal prices. However, GSU disagrees that Ms. Pitchford's recommended disallowances are appropriate or reasonable.

If the issue were simply a matter of whether GSU's ratepayers will pay higher coal prices during the reconciliation period due to GSU's inability to procure incremental coal from Cajun Electric, then the disallowances proposed by Ms. Pitchford would be adopted as a matter of course. However, this issue is not as cut-and-dried as Calvert would have the Commission believe.

GSU and Calvert have argued extensively about the tenor, frequency, and success of GSU's efforts during the reconciliation period to procure the benefits of lower-priced incremental coal from Cajun Electric. Calvert contends that GSU sat on its hands for months before pursuing legal action against Cajun. GSU, on the other hand, believes that it appropriately and aggressively pressed its case with Cajun Electric, finally resorting to legal action after Cajun Electric would not budge.

***12** GSU witness Mr. Avery Champagne provided a chronology of events relating to the incremental coal issue in his rebuttal testimony, spanning the time period of July 1987 until December 1991. GSU Ex. 76A, Sch. AJC-1. *GSU first learned of Cajun Electric's* October 1987 contract with Triton for incremental coal purchases in late 1987. *Id.* at 1. From October 1987 through mid-1991, Cajun Electric continued to enter into agreements for incremental coal purchases and pricing to the exclusion of GSU. Calvert Ex. 23B at 15-17. Similarly, Cajun Electric procured incremental rail and barge rates to GSU's exclusion. *Id.* at 18-23.

Under the JOPOA, GSU was obligated for its proportionate share of the coal on the same basis and conditions as Cajun Electric's obligations under the coal supply agreements. GSU considered its obligation to be 14 percent based on its undivided ownership interest in the common facilities. Because Cajun Electric did not allow GSU to benefit from the incremental coal supply agreements, GSU's coal supply and transportation during the reconciliation period were priced at the higher base amounts under the existing contracts. *Id.* at 25.

Calvert witness Ms. Pitchford argues that GSU should have obtained the lower incremental coal supply and transportation rates for all coal purchased and transported in excess of the contract minimums during the reconciliation period. She faults GSU for not being more diligent in reviewing the coal supply or rail transportation contracts, but acknowledges that GSU did not always get timely *information from Cajun Electric and* frequently was not permitted to review the contracts in an unedited form.[FN8] *Id.* at 30-31.

Ms. Pitchford also contended that, although GSU knew of the incremental pricing arrangements in late 1987, it did not take any 'aggressive' actions for three years. On November 8, 1990, GSU filed an amended counterclaim[FN9] against Cajun Electric in U.S. District Court, Middle District of Louisiana, alleging that Cajun Electric violated its fiduciary duties as agent to GSU and had breached the terms of the JOPOA, by not allowing GSU to benefit from the lower-priced incremental coal. GSU Ex. 46.

Ms. Pitchford alleged that GSU had a number of options available to it to receive the benefits of the lower-priced incremental coal:

1. GSU should have formally requested that Cajun procure more coal for GSU than the coal supply contract minimum. 2. GSU should have followed up on the 1988 audit letter concerning Cajun Electric's failure to include incremental coal in the average price of coal. 3. GSU's internal auditors should have requested to see the original coal or coal transportation contracts prior to the December 1990 audit. 4. GSU should have requested Cajun Electric's consent to submit the incremental coal issue for voluntary arbitration, as permitted *under the JOPOA. 5. GSU should have withheld payments* from Cajun Electric for coal supply or transportation. 6. GSU should have sought legal recourse earlier.

***13** Calvert Ex. 23B at 34.

As for Ms. Pitchford's first option, GSU admits that it never formally requested more coal than the coal supply contract minimum. GSU witness Mr. Champagne argues, however, that Cajun Electric continually insisted that GSU procure a contract for off-system sales prior to permitting it to share in the incremental coal pricing. He stated that GSU could not structure an off-system sales contract based on incremental pricing without knowing what those incremental prices were. GSU Ex. 76A at 18. Consequently, GSU disagreed with Cajun Electric that an off-system sales contract should be a prerequisite to receiving the lower-priced coal. *Id.*, Sch. AJC-1 at 5.

With respect to Ms. Pitchford's second and third options, Mr. Champagne testified that GSU followed up on the 1988 audit letter, as suggested by Ms. Pitchford, but Cajun Electric refused to discuss the issue with GSU. *Id.* at 20, Sch. AJC-1 at 6. Mr. Champagne agreed with Ms. Pitchford that GSU's internal audit department did not request to review the original coal or transportation contracts until the December 1990 audit, but he noted that the primary responsibility for reviewing the coal and transportation agreements fell on GSU's Joint Ownership personnel. Given Cajun Electric's and Burlington Northern's refusals to allow GSU to view unedited versions of these contracts, or to review the documents at all, the probability of success of GSU's audit department in such a review is doubtful.

Ms. Pitchford's final three options are admirable but of dubious value. Voluntary arbitration, like civil litigation, could have resulted in GSU being able to obtain incremental pricing, but it could just as easily have not. Whether filing suit sooner would have changed the ultimate outcome of the counterclaim is also unknown. Finally, withholding payment under a contract is generally not advisable; under the JOPOA, it could have resulted in default by GSU. GSU Ex. 45. While Ms. Pitchford's options sound reasonable at first blush, the ALJ doubts whether they would have been successful, given the apparent disregard which existed between these two utilities.

The bottom line on Ms. Pitchford's recommendations is whether Cajun Electric violated the JOPOA by refusing to permit GSU to benefit from the incremental coal pricing. Regardless of whether the ALJ or the Commission believes that Cajun Electric violated the JOPOA, the trump card is held by the U.S. District Court in Louisiana. *That court* will decide whether GSU was entitled to the incremental coal under the JOPOA, as alleged by Calvert.

Rather than second-guess the federal district court as to the effect of the JOPOA, the ALJ recommends that the Commission defer ruling on the incremental coal issue until the federal litigation is concluded, whether by order of the court, by settlement of the parties, or other manner. GSU should be required to include the proceeds of any recovery from Cajun Electric, net of associated litigation costs, as an adjustment to the over- or underrecovery balance of reconcilable fuel costs that exists at the time any such recovery is received. The regulatory treatment of any net recovery will be subject to Commission review.[FN10]

2. Nelson 6

***14** General Counsel witness Mr. Brian Almon recommended a disallowance of $645,411 on a total company basis relating to GSU's renegotiated rail transportation contract for Nelson 6 with the Railroads. Mr. Almon recommended this disallowance based on his conclusion that GSU unnecessarily delayed the negotiation of a price reduction for the base amount of coal delivered to Nelson 6. General Counsel Ex. 6 at 23-24.

Negotiations began on June 6, 1989, the earliest possible date under the 1984 rail transportation contract. These discussions continued until August 13, 1990; on February 26, 1991, they began again. Mr. Almon contended that GSU did not diligently pursue negotiations because it allowed approximately six months of no negotiation to lapse between August 13, 1990, and February 26, 1991. *Id.* at 24.

Because price adjustments under the contract are made on a quarterly basis and because the effective date of any amendment during the renegotiation is the first day of the subsequent calendar quarter, the six-month lapse meant that the effective date for any contractual changes would be April

1, 1991. *Id.* at 25. Mr. Almon argued that if negotiations had resumed before January 1, 1991, that date would have been the operative effective date for any price adjustments. He believed that GSU should have resumed negotiations in December 1990. *Id.* at 26. His calculated disallowance is based

#7 and PEF #8 to Freehill Rej. Test.]. However, the brace was actually completed before the repair of the manifold bolts, but was not a critical path item. Furthermore, the angle support did not attach to the engine itself and as far as Mr. Freehill knew the work could have been performed during the initial inspection phase or later. [Freehill Depo., (5/12/94) at 59-60]. Mr. Freehill similarly could not explain why it took 7 days (April 1-7) to replace a non-essential angle brace. [*Id.* at pp. 60-64, Att. PEF #8 to Freehill Rej. Test.].

EDITOR'S APPENDIX

PUR Citations in Text

[CAL.Sup.Ct.] Southern California Edison Co. v. California Pub. Utilities Commission, 20 Cal.3d 813, 24 PUR4th 588, 144 Cal.Rptr. 905, 576 P.2d 245 (1978).

[LA.] Re Entergy Corp., 146 PUR4th 292, Order No. U-19904, Docket No. U-19904, May 3, 1993.

[LA.] Re **Gulf States** Utilities Co., 130 PUR4th 49, Order No. U-17282-K, Docket No. U-17282, Feb. 12, 1992.

[LA.Sup.Ct.] Daily Advertiser v. Trans-La (a Division of Atmos Energy Corp. dba Energas Co.), 140 PUR4th 528 (Abstract), 612 So.2d 7 (1993).

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154 P.U.R.4th 38, 1994 WL 449069 (La.P.S.C.)

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expenses associated with the NISCO project. *Application of Gulf States Utilities Company for Approval of a Joint Venture Cogeneration Project and Treatment of Revenues*, Docket No. 7147, 14 P.U.C. BULL. 50 (March 21, 1988). The Commission found that the transfer of Nelson Units 1 and 2 to NISCO was in the public interest under PURA § 63 as long as the purchased power payments to the venture did not exceed GSU's avoided costs. Moreover, the Commission limited GSU's recovery of the NISCO purchased power payments from ratepayers in future rate proceedings to an amount not exceeding GSU's avoided costs.

GSU appealed the Commission's decision to the courts. On appeal, the Third Court of Appeals reversed and remanded the Commission's decision. The Texas Supreme Court subsequently affirmed the judgment of the Court of Appeals. *Public Utility Commission v. Gulf States Utilities Company*, 809 S.W.2d 201, 212 (Tex. 1991); *Gulf States Utilities Company v. Public Utility Commission*, 784 S.W.2d 519, 533 (Tex. App. - Austin 1990, writ granted).

***16** In addressing the Commission's decision limiting GSU's recovery of purchased power payments to NISCO, the Texas Supreme Court held:

We hold that the Commission acted arbitrarily in adopting an interpretation contrary to the plain language of its regulation. Rules 23.66(b)(2)(A) and 23.66(e) can be harmonized but not in the manner suggested by the Commission. We read Rule 23.66(e) as operating solely to set the rates that the Commission can *compel* a utility to pay for a QF's power if the utility and the QF are unable to reach a voluntary agreement. Rule 23.66(e) does not impose a ceiling on the amount the utility can *contract* to pay for a QF's power, nor does it limit the amount a utility can recover from its ratepayers under such voluntary arrangements. [Emphasis in original].

809 S.W.2d at 207.

Recognizing the Commission's regulatory authority, the Court explained that its holding did not result in automatic recovery of the NISCO payments:

Our holding that the state and federal regulations governing a utility's purchases of power from a QF do not apply to voluntary arrangements between a utility and a QF does not deprive the Commission of its regulatory authority over the amount of such contractual payments that a utility may recover from its customers. GSU may contract for any purchase price it wishes; however, whether such costs will be fully recoverable from the ratepayers will be subject to the Commission's ordinary ratemaking powers. GSU's purchase of electricity from the Venture is a fuel cost, *see* 16 TEX. ADMIN. CODE. § 23.23(b)(2)(B) (West Sept. 1, 1988), which, like any other expense, is subject to disallowance by the Commission upon a finding that the expense is unreasonable, unnecessary, or not in the public interest. [Footnote in original omitted.]

S.W.2d at 209.

Based on its holding, the Texas Supreme Court ordered the Commission to allow GSU to recover purchased power payments to NISCO in excess of avoided costs in future rate proceedings if GSU establishes, to the Commission's satisfaction, that the payments are reasonable and necessary expenses. In response to the Commission's argument that GSU could not justify the payments on the grounds that they are necessary to retain the Industrial Participants, given that the NISCO venture was already in place, the court articulated the following test:

GSU should be allowed to show that, absent the Venture, the industrial customers would have left its system because independent cogeneration was economically more attractive than remaining in the system, that the contractual rates are necessary to make the Venture more attractive than independent cogeneration, and that such rates are at the minimum level. If GSU is able to satisfy the Commission that payments above avoided costs are justified, then the Commission should determine what portion of the costs of the Venture it is reasonable and necessary for the ratepayers to bear, given the distribution of benefits from the Venture to the ratepayers and to the shareholders. [Footnote in original omitted.]

***17** S.W.2d 809 at 210.

Therefore, the supreme court has established a three-part test for GSU to meet to recover the portion of its payments to NISCO which exceed avoided costs:

1. Absent the NISCO venture, the Industrial Participants would have left GSU's system because independent cogeneration was economically more attractive; 2. The contractual rates are necessary to make NISCO more attractive than independent cogeneration; and 3. The rates are at the minimum level.

If, *and only if*, GSU satisfies this three-part test, the Commission will determine the amount of NISCO costs, if any. GSU's ratepayers should reasonably bear. In establishing this three-part test, the court has defined the required elements of the inquiry into the reasonableness of GSU's payments to NISCO. The ALJ has applied the supreme court's test to determine the reasonableness of the amount above avoided cost.

In its opinion, the supreme court also remanded for further review the issue of the appropriate allocation of the gain on the sale of the two Nelson units to NISCO between GSU's shareholders and ratepayers. The allocation of the gain on the sale is not an issue in this docket, but is instead the subject of pending Docket No. 11776, *Application of Gulf States Utilities Company for Approval of a Joint Venture Cogeneration Project and Treatment of Revenues (Remand)* (pending). While the ultimate decision with regard to the gain on the sale has yet to be addressed by the Commission, 83 percent of the fixed asset fee is currently being flowed through to the ratepayers under the rates established in Docket No. 8702, GSU's last rate case. GSU Ex. 97 at 24-25.

Beaumont, OPC, and the General Counsel also argue that the Commission must review the reasonableness of the NISCO payments under the affiliate transaction standard in PURA § 41. The affiliate standard and related issues are discussed in Section V.C.4. of the Report.

2. Whether it is Appropriate for the Commission to Consider The NISCO Issue in a Fuel Reconciliation Proceeding - Whether the NISCO Payments are Fuel Costs or Base Rate Load Retention Payments

As a threshold matter, TIEC, Beaumont, and OPC contend that GSU's payments to NISCO above avoided cost are not really purchased power expenses or fuel costs at all, but are instead base rate load retention payments to the three Louisiana industrial customers. As such, the intervenors argue that GSU cannot reconcile those non-fuel costs in this fuel proceeding.

GSU does not dispute the fact that it is purchasing electricity and load retention from NISCO, and it agrees that the NISCO payments are load retention costs. GSU Brief at 94; Tr. 739; 3449. GSU, however, argues in brief that the Commission in Docket No. 7147 and the Texas Supreme Court on judicial review both held that the NISCO payments were purchased power payments or fuel costs as well. GSU Brief at 50; Docket No. 7147, 14 P.U.C. BULL. at 58; 809 S.W.2d at 209. Although GSU argues that the characterization of its payments to NISCO as fuel costs was central to the Texas Supreme Court's opinion, the court actually characterized GSU's *purchase of electricity* from the Venture as a fuel cost. GSU is in fact purchasing something more than electricity, *i.e.*, load retention. [2] The intervenors make a very persuasive argument, assisted by GSU, that GSU's payments to NISCO above avoided cost are, in actuality, base rate load retention payments which should be considered in the context of a base rate case. The Commission has consistently held that the shareholders of the utility are to bear load retention costs, not the ratepayers. *Application of Gulf States Utilities Company for Approval of Experimental Rider to Schedules LPS and LIS*, Docket No. 7309, 13 P.U.C. BULL. 1629, 1683 (May 13, 1987); *Application of Central Power and Light Company For a Large Industrial Power Experimental Rider 16*, Docket No. 7596, 13 P.U.C. BULL 858 (Sept. 25, 1987) (mem.). In GSU's last rate case, the Commission rejected GSU's request to require Texas ratepayers to pay non-jurisdictional load retention costs. Docket No. 8702, 17 P.U.C. BULL. at 849. Although GSU's payments to NISCO may constitute load retention payments, the ALJ's decision with regard to the recovery of the NISCO payments, however, will not hinge solely on the premise that the payments above avoided cost are base rate load retention payments. Rather, it is an additional argument in favor of disallowing the NISCO payments in excess of avoided cost.

***18** *3. Discussion and Analysis of NISCO Under Supreme Court Test*

a. Whether, Absent NISCO, the Industrial Participants Would Have Left GSU's System Because Independent Cogeneration Was Economically More Attractive Than Remaining on GSU's System

The first part of the Texas Supreme Court's test for determining whether the NISCO payments above avoided costs are recoverable requires a determination of whether, absent NISCO, the Industrial Participants would have left GSU's system because independent cogeneration was economically more attractive than remaining on the system.

As a threshold matter, GSU argues that this issue was litigated in Docket No. 7147 and that the Commission is collaterally estopped from litigating it again. GSU cites Finding of Fact No. 11 in Docket No. 7147, which states:

11. The Venture's industrial participants will likely turn to self-generation if the Venture does not go forward.

14 P.U.C. BULL. at 79. [3] GSU's argument fails on three grounds. First, the supreme court has directed GSU to address this issue in the first prong of its test. Second, the doctrine of collateral estoppel applies to relitigation of ultimate issues; it does not bar relitigation merely because the outcome of two cases may appear to be inconsistent. Beaumont Reply at 9; *Tarter v. Metropolitan Savings & Loan Association*, 744 S.W.2d 928-929 (Tex. 1988). Third, assuming GSU is correct in asserting collateral estoppel applies, Finding of Fact No. 11 in Docket No. 7147 is not sufficient to meet GSU's burden on this issue. GSU must show that, absent NISCO, the Industrial Participants *would have left* the system, not that they were likely to leave.

Although GSU argued that the Commission was collaterally estopped from litigating this issue, it nevertheless attempted to demonstrate that the Industrial Participants would have left GSU's system absent the NISCO venture. GSU presented testimony from executives of Citgo, Conoco, and Vista to address the first prong of the supreme court's test.

During the mid-1980s, GSU's industrial customers were apparently concerned about the effect of the inclusion of River Bend in GSU's rate base and the termination of certain long-term gas contracts on the utility's rates. In fact, GSU has lost 578 MW of load since 1984: 484 MW in its Louisiana jurisdiction and 94 MW in Texas. OPC Ex. 17. According to Beaumont witness Mr. Pous, the Commission has sheltered the industrial classes in Texas from the full brunt of GSU's rate case increases, while the Louisiana Public Service Commission (LPSC) has placed more of GSU's rate increases on the industrial classes in Louisiana. Beaumont Ex. 14 at 22.

Mr. M. A. Johnson, Senior Vice President of Administration for Citgo, testified regarding Citgo's involvement with the NISCO project. GSU Ex. 26. Mr. Johnson was senior vice president in charge of refining and coordination for Citgo during the time the NISCO partnership agreement was negotiated. *Id.* at 2.

***19** According to Mr. Johnson, Citgo had two alternatives to NISCO: (1) smaller generation projects using gas turbine or other gas-fired equipment; or (2) larger, joint-venture projects using the petroleum coke produced as a by-product at its refinery as fuel. During the mid-1980s, Citgo and Conoco began discussions about the possibility of building a coke-fired generating plant, to be operated as a joint venture, on or near Citgo's refinery. Citgo also considered the installation of gas turbines at this time. *Id.* at 4. Mr. Johnson maintained that if the NISCO venture had not been formed with GSU, Citgo would have left GSU's system and entered into self-generation or a generation project with one of the other Industrial Participants. *Id.* at 6.

Mr. David Griffith, currently Manager of Petroleos DeVenezuela S. A. Project Development for Conoco, was Conoco's Director of Business Development prior to the NISCO discussions in late 1984. In late 1984, Conoco informed GSU of its intent to pursue self-generation options. Mr. Griffith testified that it was Mr. James Richardson, GSU's Wholesale Accounts Manager, who suggested that GSU's Nelson facilities near Lake Charles, Louisiana could form the basis of a joint project involving GSU, Conoco, and other potential cogenerators. This, according to Mr. Griffith, was the genesis of the NISCO venture. GSU Ex. 99 at 3.

Mr. Griffith testified that three alternatives to NISCO were available to Conoco: (1) the construction of a stand-alone gas turbine project; (2) a potential joint venture petroleum coke facility with Vista; and (3) purchase of cogeneration facilities owned by PPG Industries and conversion of those facilities to coke-fired boilers. Apparently, Conoco still intended to take backup power from GSU under these options. Mr. Griffith testified that Conoco was prepared to pursue self-generation in the event the NISCO project was not consummated. *Id.* at 5-6.

Mr. Gerald D. Inbody, Vista's General Manager of Engineering, represented Vista during the study and development of NISCO in 1985, as well as during the negotiation of the NISCO Partnership Agreement in 1985 and 1986. He participated in the Joint Venture Management Committee during that same time period. GSU Ex. 100 at 2.

Mr. Inbody testified that GSU proposed the Steam Users Service (SUS) incentive rate as an alternative to NISCO in 1986, after it and the Industrial Participants had begun the NISCO discussions. Tr. 4015-4016. Vista did not favor that option because it was seeking a long term solution to its electricity supply concerns which was not subject to periodic regulatory revision or review. After the FERC initially denied QF status to the NISCO project in 1987, Vista again reviewed the SUS alternative but rejected it once more for the same reasons. GSU Ex. 100 at 4.

According to Mr. Inbody, Vista had three options to NISCO: (1) a multiple gas turbine project undertaken as a joint project among Citgo, Conoco, and Vista; (2) stand-alone gas-fired turbine generators; and (3) joint venture coke-fired projects not including GSU. Vista still intended to negotiate with GSU for standby power regardless of these options. *Id.* at 4-6. Because the comparative economic benefits of NISCO were not as favorable as expected, Mr. Inbody believed that this comparative decrease would make self-generation more attractive to the industrial customers, as opposed to the SUS incentive rate. *Id.* at 7. According to Mr. Griffith, the NISCO partnership agreement, as executed, represented Vista's 'bottom line;' Vista would have rejected any further attempts to renegotiate the joint venture.

***20** There is no doubt that the Industrial Participants were considering self-generation to alleviate their concerns about GSU. But despite the seemingly unequivocal statements made by GSU's witnesses in prefiled direct testimony that the Industrial Participants reviewed these options, the claim that Citgo, Conoco, and Vista actually *would have left* GSU's system but for the consummation of NISCO is speculative and not supported by the credible evidence. Although the witnesses each discussed cogeneration options considered by their respective corporations and those entities' intent to leave GSU's system, it appears that none of the Industrial Participants actually approved any of the self-generation options discussed. Furthermore, it does not appear they were prepared to leave GSU's system to pursue one or more such options, presumably because they were so focused on NISCO. Tr. 709, 4056; Beaumont Ex. 31 at 12. There is no evidence they could have left GSU's system during the time NISCO was discussed. By one estimate, they could not have started to cogenerate, if at all, until sometime during 1991, near the end of the reconciliation period.

Finally, although GSU has gone to great lengths to attempt to prove that the Industrial Participants unequivocally would have left the system, there is surprisingly little, if any, credible contemporaneous evidence to support that conclusion. Given the absolutes in the prefiled direct testimony, the ALJ expected some credible evidentiary support for the Industrial Participants' claims that it was either to be NISCO or the train out of town. The reports and evaluations presented to support the NISCO decision uniformly *assumed* that the Industrial Participants would leave the system if NISCO were not consummated, and they seemed to give short-shrift to other available alternatives. Beaumont Ex. 36. Beaumont contends that GSU may have even facilitated the loss of load from its system by pursuing NISCO and the ALJ agrees. Beaumont Ex. 14 at 27. And although GSU and the Industrial Participants denigrated the ability of the SUS or other incentive rate to keep some portion of GSU's industrial customers' load on the system, there is contrary evidence which shows that an incentive rate could have been structured to maintain, at least partially, some of the load on the system. Beaumont Ex.

32, 33; Tr. 4022-4024. For all these reasons, the ALJ finds that GSU has failed to prove that the Industrial Participants would have left the system absent the NISCO venture.

b. Whether the Contractual Rates are Necessary to Make the NISCO Venture More Attractive Than Cogeneration

The second part of the supreme court's test for determining whether the NISCO payments above avoided costs are recoverable requires a determination of whether the contractual rates are necessary to make the NISCO venture more attractive than cogeneration.

Beaumont argues the Industrial Participants were willing to accept an SUS rate after QF status was initially denied by the FERC. Beaumont Ex. 15 at Tab 11. GSU obviously disagrees. GSU Ex. 34 at 6; GSU Ex. 92 at 18; GSU Ex. 99 at 9-10; GSU Ex. 100 at 3. As noted above, there is evidence that an incentive rate could be structured in such a manner as to retain load successfully. GSU witness Mr. Griffith testified in deposition that it was conceivable that an incentive rate with a sufficient enough discount would have reduced the incentive to participate in NISCO sufficiently to overcome any long-term or short-term objections. Beaumont Ex. 33 at 106. Mr. Griffith also stated that Conoco was indifferent to the precise price in the NISCO rate as long as the differential between the buy and sell prices was maintained. Beaumont Ex. 32 at 100.[FN11] If Conoco was indeed indifferent to the absolute level of the price, then the NISCO contract rate cannot be necessary to make NISCO more attractive than other cogeneration projects.

***21** The credible evidence supports Beaumont's and OPC's contention that GSU did not pursue incentive rates for its Louisiana industrial customers because the LPSC had required GSU's shareholders to bear the losses associated with incentive rates charged in Louisiana. GSU admits as much in brief, claiming that use of incentive rates would unfairly require GSU's shareholders to make up the revenue loss. GSU Brief at 38. The total revenue reduction, for both Texas and Louisiana, associated with the SUS rates through December 1991 totals $34,231,056, which GSU's shareholders have absorbed. OPC Ex. 47. Additionally, if GSU had opted for incentive rates instead of forming NISCO, the opportunity for profit from the sale of Nelson Units 1 and 2 would have been forgone. OPC Ex. 51 at 38.

Given the projected internal rates of return (IRRs) to the Industrial Participants, NISCO presented a favorable option for the Industrial Participants and GSU. In fact, the ALJ concurs in the intervenors' argument that NISCO was *more favorable than necessary* to prevent the Industrial Participants from leaving the system for other cogeneration options.

Beaumont witness Mr. Pous alleges that the Industrial Participants and GSU, but not GSU's Texas retail ratepayers, benefitted from the NISCO agreement. The NISCO agreement allowed the Industrial Participants to stabilize their electric costs in the face of potential base rate increases resulting from placing River Bend costs in rate base. Under the joint venture, the Industrial Participants would receive IRRs of almost 50 percent on their investment. *Id.* at 19; OPC Ex. 65. Also, the NISCO agreement permitted GSU to minimize its excess capacity situation by transferring Nelson Units 1 and 2 out of its rate base. *Id.* at 19-20; Beaumont Ex. 38 at 4. Mr. Pous observed that GSU was unable to produce a single economic analysis developed during the 1985 time period which showed a maximization of economic benefits to the ratepayers. In addition, no economic analysis of the type included in Dr. Hadaway's prudence testimony had been performed by GSU by late 1986, when the partnership agreement draft had been completed. Beaumont Ex. 14 at 21.

The ALJ concludes from the credible evidence that GSU has failed to prove that the NISCO contractual rates, as incorporated into the agreement, were necessary to make NISCO more attractive than cogeneration.

c. Whether the Contractual Rates are at the Minimum Level

The third part of the supreme court test requires a determination of whether the NISCO contract rates are at a minimum level. GSU argues in brief that it would be unrealistic to view this part of the supreme court's test as a rigid and inflexible standard of optimality. In GSU's opinion, it would be unfair to impose a standard of perfection; in order to avoid placing an impossible burden on GSU, GSU suggests that there should be 'a range of reasonableness in judging whether the [contractual] rates were at a low enough level.' GSU Brief at 86-87. The supreme court's test, however, is not ambiguous or subject to wide variation in interpretation. Consequently, the ALJ rejects GSU's attempt to interpret the third prong of the supreme court's test to include a range of reasonableness standard. Even if a range of reasonableness standard were included, however, GSU has failed to meet it.

***22** GSU asserts that it provided the Industrial Participants with only the minimum concessions necessary to keep them from turning to cogeneration, and it characterizes the NISCO project as the result of arms-length, hard-nosed negotiations. GSU Brief at 86-87. The curious aspect about this position is that GSU did not offer any credible contemporaneous evidence of those negotiations, which would have demonstrated that GSU held the line on the contractual rates. TIEC Ex. 4. In fact, the evidence demonstrates that GSU proposed the buy/sell formula ultimately incorporated into the agreement, to which the Industrial Participants apparently just simply agreed. Beaumont Ex. 14 at 37.

Further, although GSU considered the possibility of basing the buy/sell formula on its avoided cost, it never offered that option to the Industrial Participants. OPC Ex. 50 at 34. A buy/sell formula based on avoided cost would have been much lower than the buy/sell formula actually incorporated into the NISCO agreement and would have resulted in the recognition of all NISCO costs as base rate revenue reductions in GSU's Louisiana jurisdiction. Beaumont Ex. 14 at 41. GSU's position that the NISCO rate was at a minimum level damaged irreparably, in the ALJ's opinion, GSU witness Mr. Johnson's testimony that Citgo would not have ruled out other pricing possibilities. Tr. 710.

In support of its contention that it did not give up too much in negotiating the NISCO venture, GSU argued that a study of the expected IRRs for the NISCO project and other cogeneration alternatives demonstrated that NISCO's IRRs were competitive to the IRRs of other cogeneration projects. GSU Brief at 88-89. Depending upon when the calculation was done and whether the fixed asset payment was capitalized, the IRRs calculated for the NISCO project ranged from 25.7 to 31.1 percent on the low side and from 46 to 49 percent on the high side. GSU Ex. 28 at 15-16; OPC Ex. 51 at 22; Beaumont Ex. 14 at 45; OPC Ex. 65 at 10. On the other hand, expected IRRs for cogeneration alternatives ranged from approximately 20 percent to 36 percent. GSU Ex. 100; GSU Ex. 102; Beaumont Ex. 36. OPC witness Dr. Andersen testified that the fact that the NISCO venture was expected to yield returns that exceeded the hurdle rate or the rate of alternative projects suggested that the final NISCO agreement was less favorable to the ratepayers than what could have been achieved through effective negotiations. OPC Ex. 51 at 23.

Whether NISCO's expected IRRs compared favorably with the expected IRRs for other cogeneration alternatives, however, is really not the issue. As noted by Beaumont, not only did NISCO's expected IRRs far exceed the 11-19 percent level reported as necessary in the National Economic Research Associates, Inc. (NERA) study done for GSU, but the appropriate focus was not the expected IRRs to the Industrial Participants. Rather, the germane issue is whether there was a lesser priced alternative to NISCO, such as basing the formula on GSU's avoided cost. Beaumont Reply at 13.

***23** Based on the average IPS rate of 4.4 cents per KWH during the reconciliation period, less the 0.5 cents per KWH variable service fee, the average cost per KWH purchased from NISCO by GSU was 3.9 cents per KWH. TIEC Ex. 10 at 10-12. This compares to GSU's avoided cost of 1.7 cents per KWH. The net purchased power cost incurred by the Industrial Participants, excluding the purchase of surplus NISCO generation at GSU's avoided cost, was 1.5 cents per KWH, or 2.9 cents per KWH below the average IPS rate. *Id.* at 10. The actual cost of fuel used by NISCO is less than 0.5 cents per KWH. Tr. 947.

Based on the credible evidence, the ALJ finds that GSU has failed to prove that the NISCO contractual rates are at a minimum level. The fact that GSU *never proposed* a buy/sell formula based on its avoided cost or even approaching its avoided cost is a remarkable omission, particularly given the detrimental effect on Texas ratepayers of the buy/sell formula ultimately incorporated into the agreement.

d. If GSU Shows that the Payments to NISCO Above Avoided Cost are Justified, then What Portion of the Costs is it Reasonable for the Ratepayers to Bear Given the Distribution of Benefits from the NISCO Venture to the Ratepayers and the Shareholders

The ALJ has found that GSU has not satisfied the three-part test mandated by the Texas Supreme Court. Therefore, there is no balancing of the benefits of the NISCO venture between the ratepayers and the shareholders to determine what portion the ratepayers should reasonably bear. However, assuming *arguendo* the Commission reaches the sharing issue, the ALJ provides the following analysis of the appropriate portion of costs which GSU's Texas ratepayers should bear. [4] The ALJ concurs in the intervenors' contention that the appropriate sharing should be between GSU's shareholders and GSU's other Louisiana ratepayers. The NISCO payments above avoided cost should not be borne by GSU's Texas ratepayers because those amounts are, in actuality, base rate load retention payments to retain load in Louisiana. TIEC Ex. 3 at 43982-43983. None of the revenue received from NISCO is assigned to Texas; it is directly assigned to Louisiana. Tr. 2581.

Further, the alleged benefits received by GSU's Texas ratepayers from the retention of the Industrial Participants are speculative or nonexistent. GSU claims that the loss of the three industrial customers would have caused the Texas jurisdictional demand allocator to increase, thereby requiring its remaining ratepayers to make up the $17 million in lost base rate revenues. GSU Ex. 43 at 4; GSU Ex. 27 at 7. The argument that the Texas ratepayers would be harmed by the loss of the Industrial Participants, however, relies on the premise that the Commission would allow Texas ratepayers to make up the Louisiana base rate revenue losses. Given the Commission's policy of generally not permitting utilities to pass on load retention costs to the ratepayers, particularly *non-jurisdictional load retention costs*, the ALJ is dubious that the Commission would so order that recovery.

***24** Beaumont has also credibly shown that Texas ratepayers would in fact have been better off if the Industrial Participants had left the system as opposed to bearing the cost of the NISCO venture. When fuel savings realized from not serving the Industrial Participants are netted out of the estimated $17 million in base rate revenues losses, the estimated cost of losing the three industrial customers during the first year totalled $10.9 million on a total company basis, of which $4.2 million constitutes the Texas jurisdictional share. Tr. 1291-1292. This compares with the annual Texas jurisdictional share of $14.4 million above avoided cost that GSU is requesting to recover in this case.

As for GSU's argument that the ratepayers benefited from GSU's reduced cost of service due to the sale of the Nelson Units, the potential existed that the units would have been removed from rate base regardless of NISCO. Loss of the Industrial Participants' load would have reduced required generating capacity by approximately 236 MW. Moreover, GSU's reported capability was also reduced by 200 MW because GSU did not treat the NISCO capacity as a firm resource prior to 1992. In 1988, GSU had active excess reserves equal to 987 MW, as well as 443 MW of mothballed gas capacity. Currently, GSU estimates that it has 729 MW of active capacity and 405 MW of inactive capacity available for sale. Without the sale of the two Nelson units to NISCO, the Company's reserve margin would have approached 60 percent. OPC Ex. 51 at 27-28.

Assuming the Commission reaches the sharing issue, the ALJ finds that it is not reasonable for the Texas ratepayers to bear the payments to NISCO above avoided cost. While the ALJ does not necessarily advocate that the Commission operate in a vacuum, PURA appropriately focuses the Commission's jurisdiction on public utility regulation in this state.[FN12] Rather than demonstrate an indifference to GSU's other jurisdictional customers, this conclusion recognizes the limits of the Commission's authority and responsibility.

4. Affiliate Transaction Issues

a. Affiliate Standard Under PURA and the Rio Grande Case

OPC, Beaumont, and the General Counsel take the position that NISCO and GSU are affiliates and, consequently, the Commission must review the reasonableness of the NISCO payments under the affiliate transaction standard contained in PURA § 41. Beaumont urged that the amount above GSU's avoided cost be disallowed under PURA § 41(c)(1) based on the premise that the price paid by GSU to NISCO and recovered from ratepayers must be limited to the market price which would be paid to non-affiliated entities, *i.e.*, avoided cost. OPC recognized that the entire NISCO cost could be disallowed based on the failure to meet the affiliate standard, but only recommended recovery of the NISCO costs equal to or less than GSU's avoided costs. Beaumont Brief at 24; OPC Brief at 53. Because the supreme court's opinion established GSU's avoided cost as the minimum floor for recovery by GSU, this affiliate analysis will evaluate the amount exceeding GSU's avoided cost for a determination of reasonableness under the affiliate standard.

***25** The term 'affiliate' is defined in PURA § 3(i). The applicable subsection for this case is § 3(i)(6). PURA § 3(i)(6) provides:

(i) 'affiliated interest' or 'affiliate' means: (6) any person or corporation that the Commission, after notice and hearing, determines actually exercises any substantial influence or control over the policies and actions of a public utility, or over which a public utility exercises such control, or that is under common control with a public utility, such control being the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of another, whether such power is established through ownership or voting of securities or by any other direct or indirect means:

PURA § 41(c)(1) states the general standards a utility must meet to recover expenses incurred in affiliate transactions:

Payment to affiliated interests for cost of any services, or any property, right or thing, or for interest expense shall not be allowed either as capital cost or as expense except to the extent that the regulatory authority shall find such payment to be reasonable and necessary for each item or class of items as determined by the commission. Any such finding shall include specific findings of the reasonableness and necessity of each item or class of items allowed and a finding that the price to the utility is no higher than prices charged by the supplying affiliate to its other affiliates or divisions for the same item or class of items, or to unaffiliated persons or corporations.

The Commission's Fuel Rule carries forward the statutory affiliate standard. P.U.C. SUBST. R. 23.23 (b)(2)(H)(iv) provides that in the reconciliation of fuel costs, the utility has the burden of proving that:

For all fuels acquired from or provided by affiliates of the utility, all fuel-related affiliate expenses are reasonable and necessary, and that the prices charged to the utility are no higher than prices charged by the supplying affiliate to its other affiliates or divisions or to unaffiliated persons or corporations for the same item or class of items.

(I) The affiliate fuel price shall be at cost; no return on equity or equity profit may be included in the affiliate fuel price. The Commission may consider the inclusion of affiliate equity return and rate of return and rate base during the utility's general rate case; however, affiliate equity return or profit shall not be considered part of fuel costs. (II) Operational investigations of all affiliate fuel suppliers and fuel supply services shall be performed at the discretion of the Commission. The Commission may use the results of such investigations during succeeding general rate cases, fuel cost reconciliation proceedings, emergency request proceedings, and elsewhere as it deems appropriate. (III) The affiliated companies shall establish, maintain, and provide for Commission audit, all books and records related to the cost of fuel. These records shall explicitly identify all salaries, contract expenses, or other expenses paid or received among any affiliated companies, their employees, or contract employees. Under recovery reconciliation shall be granted only for that portion of fuel costs increased by conditions or events beyond the control of the utility.

***26** Generally speaking, the affiliate standards aim to prevent the recovery of expenses incurred in situations in which a monopoly utility gives an unfair advantage to an unregulated affiliate, or in which an affiliate is used to circumvent the regulatory process by passing through costs that would be disallowed as excessive if incurred by the regulated utility itself. OPC Ex. 50 at 9-10.

OPC raised the issue of NISCO being a potential affiliate transaction in Docket No. 7147. This affiliate issue, however, was not resolved in Docket No. 7147. In Finding of Fact No. 27 the Commission found that it was reasonable to address the issue of possible affiliate transactions related to the coke purchases in the applicable proceeding addressing the reconciliation of GSU's purchased power cost. Because the affiliate issue was not resolved in Docket No. 7147, it was not an issue reviewed by the Texas Supreme Court on appeal.

The affiliate standard is a very stringent standard, arguably more stringent than the test adopted by the supreme court for recovery of the NISCO-related costs. However, because the Commission expressly reserved the affiliate issue for this fuel reconciliation proceeding in Docket No. 7147, the ALJ finds that it is appropriate to determine now whether the NISCO transaction is an affiliate transaction.

The intervenors rely on the four-part test articulated in *Railroad Commission v. Rio Grande Valley Gas Company*, 683 S.W.2d 783 (Tex. App. - Austin 1984, no writ), to determine whether GSU could recover the NISCO payments under an affiliate transaction analysis. Although GSU argues that it is inappropriate to apply *Rio Grande* to the NISCO transaction because of NISCO's unique load retention objections, the ALJ disagrees. The Commission has consistently used the *Rio Grande* test to evaluate affiliate transactions, and there is no basis for not doing so in this case.[FN13] Furthermore, the NISCO project may result in an affiliate transaction regardless of any potential load retention characteristics of NISCO. [5] The *Rio Grande* decision specified four requirements which determine whether affiliate charges were just and reasonable:

1. The prices charged to the utility by its affiliate are no higher than the prices charged by the supplying affiliate to other affiliates; 2. The expenses charged by the affiliate do not include costs which may not be allowed for ratemaking purposes; 3. Each item of allocated affiliate expense is reasonable and necessary; and 4. The allocated affiliate expense reasonably approximates the actual cost of providing the service to the utility.

683 S.W.2d at 786. The application of the *Rio Grande* test to the NISCO venture is discussed in Section V.C.4.c. of the Report.

b. Whether GSU and NISCO are Affiliates

The discussion surrounding the issue of whether GSU and NISCO are affiliates focused on GSU's nominal 1 percent ownership interest versus the alleged influence and/or control GSU could wield based on the unanimous consent provisions contained in the NISCO agreement.

***27** NISCO is a general partnership under and pursuant to the provisions of the Texas Uniform Partnership Act. GSU Ex. 37 at 2. GSU does not share in the profits of NISCO and is not obligated to contribute capital to the venture or to share expenses with the Industrial Participants. The Industrial Participants share the revenues and expenses of the partnership, other than the revenues from energy sales to GSU, according to the following percentages: Citgo, 50.0 percent; Conoco, 36.5 percent; and Vista, 13.5 percent. Revenues from energy sales are shared among the Industrial Participants according to their pro rata ownership percentage of generation and their individual energy demands. *Id*. at 3.

GSU witness Mr. Smith testified that GSU's one percent partnership interest enabled it to monitor and understand the construction and operation of the new circulating fluidized bed (CFB) combustion technology employed by the joint venture. *Id*. at 4. Mr. Smith also argued that GSU maintained a nominal ownership interest in the NISCO generating units and fuel handling facilities because those units would be completely surrounded by GSU's remaining property at Nelson Station. He stated that GSU wanted to ensure that the unregulated enterprise did not infringe upon the property and/or operations of GSU's regulated utility investment. OPC and Beaumont believe, however, that the division of ownership under the agreement came about so that GSU could minimize the loss of tax benefits. OPC Ex. 50 at 17-18; Beaumont Ex. 16 at 34-36. Whatever the intent in structuring the NISCO venture, however, such intent is irrelevant to the issue of whether the effect of the NISCO agreement results in GSU's substantial influence or control over NISCO, or vice versa, regardless of GSU's one percent ownership interest.

The intervenors and General Counsel all point to the unanimous consent provisions in the NISCO agreement as proof that GSU can exert substantial influence and control over the operations of NISCO. Generally, the provisions requiring unanimous consent include major changes in operations or policies related to the joint venture generating facilities; adoption or revisions of the annual operating and maintenance schedule of the joint venture generating units; contracting for major purchases, fuel, and limestone; and staffing of key personnel for the joint venture.[FN14] The existence of these unanimous consent provisions gives GSU the ability to participate in the venture far in excess of its nominal one percent ownership interest.

The NISCO management committee is comprised of no more than three members from each NISCO participant, including GSU. The management committee has the exclusive authority to control, manage, and direct the business of the NISCO venture and to take all actions necessary to further the purpose of the NISCO agreement. The chairman and vice chairman of the management committee are elected by the committee as a whole. Although GSU has three representatives on the management committee, none of them hold an elected position with the committee. GSU Ex. 37 at 5-6. There are no officers or directors of GSU which are officers and/or directors of NISCO. GSU's representatives on the management committee are not officers or directors of GSU.

***28** The senior member or the designate of each participant may vote on behalf of each NISCO participant. Each participant has a number of votes which is equal to its ownership interest. All actions of the management committee require a majority of at least 65 percent of the voting power, except when a unanimous vote is required. *Id.* at 7. Seventy-five percent of the participants are necessary for a quorum, with GSU constituting 25 percent. OPC Ex. 26. [6] Because GSU has not invoked any of the unanimous consent provisions of the partnership agreement, it argues that no affiliate relationship exists because actual exercise of control is required by PURA § 3(i)(6). While it is true that the language of the first clause of PURA § 3(i)(6) requires a finding of the actual exercise of substantial influence or control over the public utility by the alleged affiliate, the third clause in the provision does not require such.

The third clause of PURA § 3(i)(6) requires a finding that the person or corporation is under common control with a public utility, such control being the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of another. While it also could be argued that not invoking the unanimous consent provision indicates substantial influence and control by GSU, the intervenors and General Counsel focus on the third clause of PURA § 3(i)(6) in support of a finding of an affiliate relationship.

OPC and Beaumont argue that nearly all of the significant management policy actions by the NISCO management committee require unanimous consent. OPC Ex. 50 at 19; Beaumont Ex. 16 at 22. GSU itself recognized that in most critical cases, unanimous consent of the four voting members of the management committee is required. Beaumont Ex. 15, Tab 7. Because GSU's consent is required for these actions, the intervenors and General Counsel conclude that GSU has the power to exercise substantial influence or control over NISCO. The ALJ concurs in this conclusion. While GSU witness Mr. Smith argued that invoking the unanimous consent provisions merely resulted in the requirement of good faith negotiations among GSU and the Industrial Participants, the fact remains that withholding consent in certain instances could be used by GSU, or any of the Industrial Participants for that matter, as leverage in negotiations or decisions regarding policy or management.

Mr. Inbody testified on rebuttal that the partnership agreement required that key decisions be made by unanimous consent in order to ensure that Vista was not disadvantaged by its minority ownership interest, especially with regard to steam production and sales and fuel supply. GSU Ex. 100 at 11. Again, as stated earlier, the intent of the parties in structuring the agreement is irrelevant to whether the effect of the agreement results in an affiliate relationship.

Beaumont witness Mr. Lawton also testified that NISCO had the power to exercise influence and control, directly and indirectly, over the management policies and actions of GSU. He cited the requirement that costs for modifications to GSU's common facilities at the Nelson station must be discussed and approved by GSU and NISCO prior to commencing any expenditure, provided that approval is not unreasonably withheld. GSU Ex. 34, Sch. FR.B-2 at 43.

***29** NISCO is required to pay a share of the O&M and capital expenditures for its use of common facilities. If GSU decided to modify the common facilities, it would notify the NISCO management committee which may accept the proposed modification and freely participate in the funding or may reject the proposed modification. GSU Ex. 95 at 17. GSU could still proceed with the project and require NISCO to pay its proportionate share of the expenditures, regardless of whether NISCO consented by demonstrating NISCO's derived benefit from the facility's modification. GSU Ex. 97 at 17. It is not clear from Mr. Smith's testimony, however, what would occur if NISCO refused to accept GSU's demonstration of derived benefit.

GSU is also the buyer of last resort if an Industrial Participant withdraws from the NISCO venture, provided that GSU is not required to acquire a greater than 50 percent interest in the project. GSU Ex. 34, Sch. FR.B-2 at 188-189. Mr. Smith contended that this provision was included in the partnership agreement to protect the Industrial Participants, who wanted assurance of an ongoing project in the event of the withdrawal of one of the partners. GSU Ex. 95 at 18.

With regard to NISCO's option on Nelson Unit 3, Mr. Smith argued that NISCO only had the right to initiate negotiations with GSU for the purchase of Unit 3; GSU had no obligation, however, to sell Unit 3. GSU was free to enter into negotiations about Unit 3 with any third party. If such negotiations occurred, NISCO's option on Unit 3 would be suspended until the negotiations between GSU and the third party were either completed or dissolved. *Id.* at 18-19. [7, 8] The ALJ agrees with OPC, Beaumont, and the General Counsel that GSU, through the unanimous consent provisions, has the power to direct or cause the direction of the management and policies of NISCO, and vice versa. Therefore, GSU and NISCO are affiliates under PURA § 3(i)(6). Consequently, the NISCO venture must be reviewed under the affiliate standard found in PURA and the Commission's substantive rules.

c. Application of Affiliate Standard to NISCO Payments

GSU argues that the first requirement in the *Rio Grande* test cannot be applied to the NISCO transaction because NISCO, the supplying affiliate, does not supply power to any other entity. Therefore, it contends there is no way to compare the price NISCO charged GSU to the price NISCO charged other entities. While GSU correctly contends that the first requirement in the *Rio Grande* test cannot be literally applied to the NISCO transaction, that does not *per se* preclude any application of the requirement. Indeed, both GSU and the intervenors offered alternative comparisons to effectuate the first mandate stated in *Rio Grande*.

GSU witness Dr. Samuel Hadaway's alternative analysis compared the net price GSU charged NISCO with the price GSU charged its SUS incentive rate customers, rather than comparing the price NISCO charged GSU versus the price NISCO charged to other non-affiliate entities. Dr. Hadaway believed that by showing that NISCO and the Industrial Participants were left no better off than non-affiliate incentive rate customers, his analysis would demonstrate that no self-dealing was present in the NISCO transaction. GSU Ex. 28 at 4. He believed that the appropriate question was whether the price charged by NISCO and paid by GSU was no higher than GSU paid in the form of price discounts for similar load retention benefits from other non-affiliate customers. *Id.* at 5.

***30** In his analysis, Dr. Hadaway used SUS rates as the relative comparison to NISCO's net cost because those rates were the alternative load retention rates available at the time the NISCO decisions were made. *Id.* at 11. Dr. Hadaway provided the following comparison of NISCO rates, the SUS rates, and the general large industrial service (LIS) rates projected during the first five years of the NISCO contract:

1987 NISCO PROJECTED RATE COMPARISONS

Cents/KWH

	YEAR					
	AVG.	*1987*	*1988*	*1989*	*1990*	*1991*
NISCO RATE	3.96	2.73	3.63	4.36	4.87	4.24
SUS RATE	3.87	3.16	3.60	4.07	4.20	4.34
LIS RATE	5.71	4.56	5.30	5.99	6.19	6.39

Source: Conoco September 1986 NISCO Analysis.
SUS rates are extrapolated
from 1987 actuals at the same percentage changes
as projected for LIS rates.

Based on this data, Dr. Hadaway concluded that during the first five years of the NISCO contract, the net cost of electricity projected for the Industrial Participants was no lower than the prices charged to other non-affiliated incentive rate customers. Because the net NISCO rate was dependent on GSU's payments for NISCO energy, the price was no higher than the SUS discounts provided to non-affiliate companies for the same load retention purpose. Therefore, he concluded that GSU's payments to NISCO were reasonable and necessary, even if they were considered to be an affiliate transaction. *Id.* at 12-13.

OPC and Beaumont contend that Dr. Hadaway's focus on *the price GSU charged NISCO* is improper - they assert the appropriate perspective is from the perspective of the *buyer of the affiliate service*, in this case GSU and other potential buyers of the service provided by NISCO. OPC Ex. 50 at 27; Beaumont Ex. 16 at 42. The ALJ concurs. [9] Because there are no other buyers of the service provided by NISCO, OPC witness Mr. Johnson applied a market test to determine the reasonableness of the NISCO transaction. OPC Ex. 50 at 25. According to Mr. Johnson, there are two ways to apply the market test: (1) comparing the NISCO cost to GSU versus the cost to GSU to acquire power in lieu of the NISCO-generated energy; or (2) comparing the NISCO cost to GSU versus the price at which NISCO would sell power if GSU did not purchase all of the NISCO-generated power. Because GSU does not make any other purchases of power which exceed its avoided cost, the price NISCO charges GSU far exceeds the price GSU would pay for purchased power from other sources. As for the price at which NISCO could sell power if GSU did not purchase all of its output, GSU did not effectively rebut the proposition that the current NISCO price exceeds the price NISCO could charge on the open market.

As for the three remaining steps of the *Rio Grande* test, Beaumont witness Mr. Pous succinctly and correctly evaluated the sufficiency of the evidence with respect to the NISCO transaction and the affiliated expenses. The ALJ concurs in his contention that GSU failed to prove: (1) that the expenses included in the NISCO payments did not include expenses which would be disallowed for ratemaking purposes; (2) that the allocated percentages of common facilities at the Nelson Station between GSU and NISCO were appropriate or reasonable (the initial allocation was split on a 70/30 percent basis to GSU and NISCO, respectively, but was subsequently modified to 55/45 percent to GSU and NISCO); (3) that the costs incurred by NISCO and paid by GSU were reasonable; and (4) that the allocated amounts reasonably approximated the actual cost of service incurred. Beaumont Ex. 14 at 52-57. Indeed, the evidence show that the allocated costs are actually based on estimates. OPC Ex. 20. [10] While GSU argued that the NISCO payments did not exceed actual cost based in part on the value of retaining the Industrial Participants on the system, the actual cost principle looks to actually incurred expenditures. OPC Ex. 50 at 39. Based upon a review of 1990 and 1991, the only two years for which audited data was available, GSU's payments to NISCO for power exceeded the cost of providing the service. In 1990, the NISCO costs were $49.9 million, or 20 percent lower than GSU's payments to NISCO. During 1991, the NISCO costs were $45.6 million, or 26 percent lower than GSU's payments to NISCO. *Id.* at 40. [11] Based on the credible evidence, the ALJ finds that GSU has failed to show that the affiliate expenses in the NISCO transaction are just and reasonable under PURA § 41(c)(1) and P.U.C. SUBST. R. 23.23(b)(2)(H)(iv). The ALJ recommends that the amount of the NISCO payments above avoided cost be excluded from GSU's reconcilable fuel balance.

***31** One final issue must be briefly addressed here. The General Counsel, in brief, argued that to the extent GSU's payments to NISCO represented profits to the Industrial Participants, that portion should be excluded from reconcilable fuel under PURA § 41(c)(1) and P.U.C. SUBST. R. 23.23(b)(2)(H)(iv)(I). During the reconciliation period, NISCO's net income was approximately $53.4 million, which the General Counsel recommended be disallowed. General Counsel Brief at 16-17.

The General Counsel's argument has been roundly criticized, both by the intervenors and by GSU. Had this theory been advanced in the General Counsel's case at all, the ALJ and the other parties could have more thoroughly reviewed this recommendation. As it is, the ALJ does not even have the benefit of a reply brief from the General Counsel. Consequently, the ALJ declines to adopt the General Counsel's recommendation.

5. Prudence Review of NISCO Payments

GSU provided a traditional prudence analysis to support its requested recovery of the NISCO payments. There is disagreement among the parties as to whether a prudence review of the NISCO costs is necessary or appropriate in this case, given the three-prong test mandated by the supreme court. *See, e.g.*, GSU Brief at 48; Beaumont Reply at 18. While it is clear that GSU must meet the test mandated by the supreme court to recover the NISCO payments above avoided cost, it is not so clear if or how GSU's prudence analysis fits within that mandated test. Because the ALJ has found that GSU failed to prove that the NISCO payments above avoided cost are justified under the supreme court's test, an evaluation pursuant to the Commission's traditional prudence analysis is arguably academic.

Assuming, however, that the Commission must also review the NISCO payments under the prudence standard stated in Section IV. of the Report, the ALJ finds that GSU has failed to prove that it prudently and reasonably incurred the NISCO payments above avoided cost. Therefore, those amounts should be disallowed.

GSU witness Dr. Hadaway presented GSU's cost/benefit analysis of the NISCO payments. He compared the expected costs resulting from the Industrial Participants' departure from GSU's system to the expected costs of the NISCO project under four scenarios. Dr. Hadaway's analysis did not address the likelihood of loss of load; he assumed that the load from the Industrial Participants would be lost.

Beaumont argues that GSU's prudence analysis is flawed because it uses 1985 information, instead of information known or knowable to GSU in April 1988 when the NISCO agreement was consummated. As such, it did not include any of the effects of the rate base inclusion of River Bend on GSU's rates which were known in 1988, but did include an understated IPS rate and overstated gas prices. Beaumont Reply at 19-20. Including information from 1988 would apparently have decreased the benefits from NISCO calculated by Dr. Hadaway. Additionally, Dr. Hadaway's analysis failed to consider the jurisdictional issue or the possibility that a portion of the Industrial Participants' load could have been maintained. OPC Ex. 51 at 59.

***32** Dr. Hadaway's four scenarios were derived from alternative avoided cost rates and rates paid by the Industrial Participants. Each scenario compared customer costs with and without the NISCO venture; each used a 10 percent discount rate to bring all payments to present value status. In the first three scenarios, Dr. Hadaway used GSU's base case, high, and low marginal fuel cost estimates, respectively. The fourth scenario escalated the IPS base rate to demonstrate his contention that GSU's ratepayers were insulated from IPS base rate increases by the NISCO contract pricing provisions. GSU Ex. 27 at 16.

The basic comparison in Dr. Hadaway's four scenarios contrasted the cost to the ratepayers under the NISCO contract to the cost the ratepayers would have paid had the Industrial Participants left the system for cogeneration. For his cogeneration option, Dr. Hadaway assumed that it would have taken 2.75 years for the Industrial Participants to construct their cogeneration facilities. He assumed that the Industrial Participants remained on GSU's system during this construction period and paid the full standard tariff non-fuel revenue of $21.3 million per year. After the cogeneration facilities were constructed, he assumed the Industrial Participants paid stand-by fees and facility charges of $4.3 million per year. He also assessed an additional cost to remaining ratepayers when marginal fuel prices were less than the system average and credited them when marginal fuel prices were above the system average. Under Dr. Hadaway's base case scenario, he computed total customer savings over the 20-year life of the contract to be $199.5 million, which equates to $57.9 million on a present value basis. *Id.* at 17; Sch. SCH-1 at 1.

In his second scenario, Dr. Hadaway assumed higher marginal fuel costs. This scenario resulted in a total customer benefit under the NISCO contract of $230.3 million which translates into a present value benefit of $69 million. *Id.* at 19; Sch. SCH-1 at 2. The higher marginal fuel rates assumed in the second scenario create a higher customer fuel benefit when marginal fuel rates exceed average fuel rates. Under Dr. Hadaway's third scenario, which assumes that the marginal fuel prices were lower, the NISCO contract provides a total customer benefit of $182.4 million, which results in a present value of $51.7 million. *Id.* at 19; Sch. SCH-1 at 3. For his final scenario, Dr. Hadaway assumed a higher IPS base rate. Under this fourth scenario, the present value benefit to the ratepayers is $73.9 million. GSU Ex. 27, Sch. SCH-4 at 4. Dr. Hadaway concluded that this result demonstrates that ratepayers are insulated from increases in the IPS rate under the NISCO agreement. GSU Ex. 27 at 20.

Beaumont witness Mr. Daniel Lawton testified that Dr. Hadaway's analysis was flawed and did not support GSU's decision that the NISCO project was the best alternative for GSU's ratepayers. Relying on a straight MWH comparison, he testified that the NISCO power costs are excessive. Based on GSU's projected fuel year ending June 30, **1993**, the total cost of generated and purchased power estimated by GSU is $574,528,321, of which $32,008,369 is attributable to NISCO. Mr. Lawton calculated the NISCO power costs to be approximately $39.52/MWH, which is high when compared to GSU's system average MWH power cost of approximately $19.25/MWH. The next highest system power cost, excluding NISCO, is Willow Glen 2 power at approximately $22.55/MWH. The purchased power cost from other cogenerators is $16.34/MWH. Beaumont Ex. 16 at 8; Sch. DJL-3.

***33** Also, Mr. Lawton disagreed with several of Dr. Hadaway's assumptions and the resulting calculations, making a number of adjustments to the former's analysis. First, in addition to reviewing the costs incurred if the Industrial Participants left the system for cogeneration and the costs incurred under the NISCO venture, Mr. Lawton analyzed GSU's option to sell Nelson Units 1 and 2 to the three industrial customers on a non-participating basis. Beaumont Ex. 16 at 16-17. In his opinion, the sell-but-not-participate option would have resulted in savings to GSU's ratepayers because it would remove excess capacity from GSU's system. He believes that GSU ignored this outright sale option because of a concern that shareholder benefits would be limited. *Id.* at 17; Beaumont Ex. 15 at Tab 1. When the outright sale option is considered, Mr. Lawton asserts that the NISCO net cash flow does not equal the $57.9 million benefit calculated by Dr. Hadaway, but rather results in a $27,755,869 detriment to ratepayers. Beaumont Ex. 16 at 18; Sch. DJL-5.

In calculating this $27 million detriment, Mr. Lawton used a 12 percent discount rate instead of the 10 percent discount rate used by Dr. Hadaway. Additionally, he assumed that the industrial customers would need only 1.5 years, as opposed to Dr. Hadaway's assumed 2.75 years, to work out a transmission arrangement and construct a steam line before beginning cogeneration. Although Dr. Hadaway disagreed with these two adjustments, they did not make a material difference to the analysis in his opinion. GSU Ex. 91 at 9.

Dr. Hadaway strongly disagreed, however, with three other adjustments made by Mr. Lawton. Those three adjustments are as follows:

1. In the calculation of computed fuel savings under the cogeneration option, Mr. Lawton used 1,517,828 MWH to reflect the system load lost if the three industrial customers left the system, compared to Dr. Hadaway's figure of 1,411,580 MWH, because the actual sales level of the industrial customers was 1,517,828 MWH. Beaumont Ex. 16 at 18. 2. Mr. Lawton added $3 million per year to the estimated cogeneration stream to reflect GSU's assumptions that management services provided to the NISCO project could generate that revenue under the sell-but-not-participate option. *Id.* at 19. 3. Mr. Lawton deducted $4 million per year for the first ten years from NISCO's contribution to system

fixed costs to account for GSU's receipt of purchase payments from the industrial customers under the sell-but-not-participate option. *Id.* at 21.

After making these adjustments to Dr. Hadaway's quantification, Mr. Lawton computed a detriment to GSU ratepayers of $27,755,869. *Id.* at 21; Sch. DJL-5.

With regard to the calculation of computed fuel savings under the cogeneration option, Dr. Hadaway argued that Mr. Lawton incorrectly assumed that the cogeneration facility would operate at a 100 percent capacity factor, resulting in a 1,517,828 MWH load loss. Dr. Hadaway believed it was more realistic to assume a lower capacity factor, and thus a lower MWH figure, because a portion of the energy used by the Industrial Participants would be provided by GSU under stand-by arrangements. Dr. Hadaway claimed that this adjustment resulted in a $4.4 million overstatement of the present value fuel savings from the cogeneration option. GSU Ex. 91 at 9-10.

***34** Mr. Lawton explained that he assumed a 100 percent capacity factor rather than Dr. Hadaway's 93 percent capacity factor, because the higher capacity factor served as a proxy for calculating the revenue received by GSU for stand-by power in the event the cogeneration facility shut down. Tr. 1807. Dr. Hadaway assumed a 93 percent capacity factor but did not include any revenue that GSU would receive for additional sales of power to the industrial customers. Mr. Lawton's MWH adjustment accounting for revenues received for stand-by service does not appear to be unreasonable, although expecting a 100 percent capacity factor is unrealistic. Assuming Dr. Hadaway's contention is correct, Mr. Lawton may have overstated the savings from the cogeneration option, but not to the extent claimed by Dr. Hadaway.

Dr. Hadaway next contended that Mr. Lawton double-counted the industrial customers' payments for Nelson Units 1 and 2 O&M expenses. Mr. Lawton added $3 million per year as an O&M services fee paid to GSU for operating the cogeneration facility. Dr. Hadaway argued that because Mr. Lawton had already removed the $3 million from cost of service and added it to the cogeneration benefits under his sell-but-not-participate option, Mr. Lawton's analysis directly credited cogeneration benefits for the same O&M payment twice. Dr. Hadaway testified that this double-counting resulted in a $19.9 million present value overstatement of the cogeneration benefits. GSU Ex. 91 at 10-12. Because GSU estimated the value of its management services to the industrial customers under the sell-but-not-participate option as $3 to $8 million annually, however, it is reasonable to account for that revenue under the sell-but-not-participate option as Mr. Lawton did. Beaumont Ex. 15, Tab 1 at 3.

Dr. Hadaway identified Mr. Lawton's third mistake as his subtraction of $4 million per year from the NISCO contribution to system fixed costs, resulting in an additional $22.6 million overstatement of the present value benefit of cogeneration. GSU Ex. 91 at 12. Dr. Hadaway argued that because Mr. Lawton did not include the gains from the sale in his analysis, his subtraction of the gains on the sale further reduced NISCO customer benefits. Mr. Lawton's subtraction, however, was based on GSU's expectation that it would have to return the gain on the sale to ratepayers over a five- to ten-year period. The ALJ believes it is reasonable to recognize that eventuality.

Although Dr. Hadaway contended that the combined present value effect of Mr. Lawton's adjustments was an overstatement of the cogeneration benefits of approximately $46 million, the credible evidence shows otherwise. Except for Mr. Lawton's use of a 100 percent capacity factor, the ALJ finds Mr. Lawton's adjustments to be reasonable. Therefore, although Mr. Lawton's adjustments may have slightly overstated the benefits of the cogeneration alternative, the ALJ does not believe it did so to the extent alleged by Dr. Hadaway. Based on the credible evidence, the ALJ finds that GSU imprudently incurred the NISCO costs exceeding avoided cost.

6. Miscellaneous NISCO Issues

***35** *a. Whether a Portion of the NISCO Payments are Non-Reconcilable Because they Include Taxes and Return Associated with Capital Cost or Contain Purchased Power Capacity Costs*

In the event the Commission allowed recovery of all or a portion of the NISCO payments, TIEC witness Mr. Pollock testified that a portion of the payments should not be treated as a reconcilable fuel expense because they included capacity-related costs. TIEC Ex. 10 at 16. Mr. Pollock recommended that the non-reconcilable costs be collected through a purchased cost recovery factor (PCRF). Although he did not recommend that costs above avoided cost be recoverable, he concluded that a PCRF would be the proper mechanism for recovering those payments if the Commission were to disagree with his primary recommendation. *Id.* at 21. Based on his calculations, Mr. Pollock found that 51 percent of the NISCO payments, or $100.9 million total system, would be non-reconcilable. The Texas retail portion of the non-reconcilable payments would total $38.1 million. *Id.* at 19; TIEC Ex. 10A, Sch. 8 (Revised). Mr. Pollock concluded, however, that GSU should be allowed to recover the NISCO payments in the amount up to GSU's avoided costs.

GSU and Beaumont both disagree with TIEC's alternative recommendation that payments to NISCO should be recovered through a purchased power recovery clause (PCRF).[FN15] Although GSU witness Mr. Beekman disagreed that a portion of the NISCO payments should be considered non-reconcilable firm capacity costs, he agreed that the appropriate method for recovering any such purchased power capacity costs from a QF such as NISCO was through a PCRF clause. GSU Ex. 97 at 20.

Although Mr. Pollock's prefiled testimony on this issue was somewhat unclear, TIEC is *not requesting* the approval of a PCRF here. Mr. Pollock's discussion regarding PCRF clauses was an alternative recommendation to his primary recommendation that GSU not be permitted to recover the payments to NISCO in excess of GSU's avoided costs. Because the ALJ has recommended that GSU not recover the costs above avoided cost, she does not reach the issue of whether a PCRF should be approved.

Additionally, OPC witness Mr. Johnson argued that the NISCO payments were not reconcilable because they included taxes and capital associated with capital costs, while Beaumont witness Mr. Pous argued that the NISCO payments included capital costs paid for Nelson Units 1 and 2. OPC Ex. 50 at 41; Beaumont Ex. 14 at 36. GSU witness Mr. Beekman testified that, to the extent that the NISCO costs include taxes and return, it should not be treated any differently from any other fuel supplier including the costs of its product in a profit in its sales price. GSU Ex. 97 at 16.

Again, because the ALJ recommends that GSU not recover the NISCO costs above avoided costs, she does not reach the issue of whether the costs improperly include taxes and capital associated with capital costs, or capital costs paid for Nelson Units 1 and 2. The ALJ notes, however, that P.U.C. SUBST. R. 23.23(b)(2)(H)(iv)(I) precludes recovery of affiliate equity profit.

***36** *b. Whether the NISCO Contract is Discriminatory*

GSU and the intervenors both raise the issue of potential discrimination, but from different perspectives. Beaumont and OPC contend that the NISCO agreement discriminates against other cogenerators because no other cogenerators are paid above GSU's avoided cost. Also, because the Industrial Participants are billed at combined delivery points, the intervenors aver that no other cogenerators are able to take advantage of their combined diversity of demand. Beaumont Ex. 14 at 47-48; OPC Ex. 51 at 44. On the other hand, GSU surprisingly argues that it would be discriminatory to base the NISCO formulary rate on avoided cost because it cannot make such a rate equally available to all of its industrial customers who are similarly situated. GSU Brief at 84.

The allegation of discrimination, regardless of the perspective, is a red herring. Notwithstanding any of the alleged costs or benefits resulting from the NISCO venture, the fact remains that no other cogenerators are similarly situated with the Industrial Participants. PURA does not prohibit reasonable discrimination under such circumstances. PURA § 38.

7. Summary of ALJ's Recommendation

The ALJ cannot shake the impression that GSU, threatened by the potential loss of the industrial customers and experiencing an excess capacity situation, latched onto the NISCO project as a lifesaving proposition. As a result, GSU and the Industrial Participants focused exclusively on NISCO, to the detriment of effectively exploring other possible options and other means by which to structure the NISCO rates. Although GSU offered the SUS rate as an alternative on isolated occasions, it appears that that alternative, as well as any other incentive rate option, never received the attention it was due. That GSU never even proposed a pricing formula based on, *or even near*, its avoided cost is remarkable, and perhaps best demonstrates its utter disinterest in exploring other available options.

Based on the credible evidence, the ALJ recommends that the NISCO payments above avoided cost be disallowed because GSU has failed to meet the burden of proof required by the Texas Supreme Court. For the reconciliation period, this results in a disallowance of $107,646,209. Additionally, the ALJ finds that GSU and NISCO are affiliates under PURA § 3(i)(6) and that GSU has failed to prove the reasonableness of the affiliate expenses in excess of avoided cost under PURA § 41(c)(1) and P.U.C. SUBST. R. 23.23(b)(2)(H)(iv). Finally, the ALJ finds that GSU imprudently incurred the NISCO costs above avoided cost.

D. Off-System Sales Adders

During the reconciliation period, GSU's total off-system sales equalled $19,214,350. Of this amount, $14,948,275 was classified by GSU as reconcilable fuel revenue which reduced GSU's reconcilable fuel costs. The remaining $4,266,075, or adder, was classified as non-reconcilable non-fuel revenue. GSU Ex. 29A, Sch. FR.C-3 at 38. The effect of classifying the adder as non-reconcilable was that the adder did not reduce GSU's reconcilable fuel balance but was instead retained by the shareholders.

***37** Calvert, TIEC, and the General Counsel argued that GSU should not be permitted to retain 100 percent of the profit from the off-system sales during the reconciliation period, although they differed in certain respects as to how much should be classified as reconcilable. Calvert would classify the entire $4,266,075 as reconcilable. TIEC subtracted $551,372 in incremental O&M expenses from the $4,266,075 adder to reach its recommendation that $3,674,703 be classified as reconcilable. The General Counsel recommended that 75 percent of $4,266,075, or $3,199,556, be classified as reconcilable.

This section of the Report will discuss the appropriate treatment of adders for the *historical* reconciliation period. Section VII.E. of the Report will discuss the *prospective* treatment of adders during the fuel year.

1. GSU's Accounting Treatment of Off-System Sales

Prior to 1990, GSU accounted for off-system sales as credits to FERC Account 555, Purchased Power. GSU Ex. 29 at 7-8. The energy portion of the credits reduced GSU's reconcilable fuel expenses; the adders, or non-fuel costs related to those sales, were treated as non-reconcilable. In December 1990, GSU made accounting adjustments retroactive to the beginning of 1990 to adjust both off-system KWH sales and the related dollar amounts, previously recorded as credits to FERC Account 555, to FERC Account 447, Sales for Resale. GSU witness Mr. Willis testified that this reclassification was mandated by FERC for other companies in 1991, and that GSU has continued to follow this accounting methodology. Consequently, the energy portion of the off-system sales amounts recorded in FERC Account 447 has been reclassified in this docket to reduce GSU's reconcilable fuel costs. According to Mr. Willis, this change in the financial accounting classification of off-system sales has not impacted the level of reconcilable fuel costs. *Id.* at 7.

As noted in Section V.B.1. of the Report, GSU participates with Cajun Electric in Big Cajun 2, Unit 3. In May 1991, GSU adjusted its books to reflect the assignment of its 42 percent share of energy in Big Cajun to Cajun Electric. This assignment was then offset by off-system sales in FERC Account 447. Mr. Willis testified that although there are no fuel expenses associated with this energy generation, given that Cajun Electric burns its coal instead of GSU's coal, the related adder of this off-system sale is recorded as a credit in FERC Account 447 and is used to reduce non-reconcilable fuel costs. *Id.* at 7-8.

2. Whether the Off-System Sales Adders During the Reconciliation Period Should be Treated as

Reconcilable and the Appropriate Allocation, if any, Between the Ratepayers and Shareholders

With respect to the characterization of off-system sales adders during the reconciliation period, GSU and the parties base their respective positions on differing interpretations of Commission precedent, or more precisely, on differing Commission precedent.

38 GSU first argues that its proposed non-reconcilable treatment of off-system sales adders is consistent with its last rate case, Docket No. 8702. Mr. Beekman argued that the Commission set GSU's fuel factor there without including the margins or profits from off-system sales as an offset or credit to GSU's reconcilable fuel expense. Consequently, GSU retained 100 percent of the profit from those sales. GSU Ex. 97 at 57-58. GSU now alleges that a change in the treatment of the reconciliation period adders would constitute improper retroactive treatment, reopen a settled case, and potentially result in financial write-offs. GSU Brief at 126.

It is doubtful, however, that the Commission explicitly determined that off-system sales adders were to be treated as non-reconcilable in Docket No. 8702 because the issue was neither contested, argued in briefs, or presented to the Commission in oral argument. Tr. 3866-3867. Because GSU had removed the off-system sales adders from both its reconcilable fuel expense and its non-reconcilable base rate revenue requirement in Docket No. 8702, any classification of the adders in this case as reconcilable would not be a retroactive change, as alleged by GSU. This docket is the first time the Commission has had the opportunity to address the appropriate treatment of expenses and revenues from the reconciliation period.

GSU also relies on Docket Nos. 8588 and 9945 in support of its position that its proposed treatment should be adopted, or at the very least, that 100 percent of the profits should not be allocated to the ratepayers. In Docket No. 8588, the Commission ordered on rehearing the exclusion of the profits from off-system economy energy sales for the reconciliation period in El Paso Electric Company's (EPE) reconcilable fuel balance, but permitted the allocation of such profits - 75 percent to the ratepayers and 25 percent to EPE - on a prospective basis. The Commission stated that it was appropriate that EPE and the ratepayers prospectively share in the profits in recognition of the ratepayers' payment for the plant generating the power sold off-system and the provision of an incentive to the utility to engage in the sales. *Application of El Paso Electric Company for Reconciliation of Fuel Costs*, Docket No. 8588, 16 P.U.C. BULL. 1311, 1355-1356 (Oct. 23, 1990).

On appeal, the Court of Appeals upheld the Commission's allocation of the profit from off-system sales, finding that the division and apportionment of future revenues amounted to an agency interpretation of one of its rules, *i.e.*, the Fuel Rule. The Court saw nothing unreasonable or *ultra vires* in the Commission's interpretation. *City of El Paso and Public Utility Commission of Texas vs. El Paso Electric Company*, No. 3-92-038-CV, slip op. at 13 (Tex. App.-Austin, March 10, **1993**, n.w.h.). OPC argues that the Commission still has the discretion to allocate profits from off-system sales in a different manner than in *City of El Paso* if the allocation is supported by the facts and policy considerations in the record. *Id*. at 12-13. The ALJ agrees.

39 In Docket No. 9945, EPE's last rate case, the Commission allowed EPE to retain the profits from its off-system sale to La Comision Federal de Electricidad de Mexico (CFE) for two reasons: (1) EPE's Palo Verde Unit 3 was not included in rate base, and (2) EPE's financial condition was found to be extremely poor. *Application of El Paso Electric Company for Authority to Change Rates*, Docket No. 9945, Findings of Fact Nos. 212A, 216, 217, 218, 18 P.U.C. BULL. 9, 578-579 (February 6, 1992). The Examiner's Report enumerated the following factors as relevant to the determination of allocation of profits:

1. The ratepayers' contribution to plant used for the sales; 2. The need to provide an incentive for the utility to pursue such sales; 3. The impact of the proposed allocation on the utility's financial strength; 4. The dividends paid to the shareholders; 5. Any extraordinary burden borne by the ratepayers because of the sales; and 6. Any advantages enjoyed by the shareholders because of the sale.

Docket No. 9945, 18 P.U.C. BULL. at 287. In addition to these six factors, GSU proffered a factor addressing its need to cover the variable O&M expense caused by the off-system sales, as well as one involving whether the treatment of adders is retrospective or prospective. In GSU's opinion, the other factors listed in Docket No. 9945 are of 'modest' importance, contending that the ratepayers' contribution to the plant, the dividends paid to the shareholders, the burdens borne by the ratepayers, and the advantages enjoyed by the shareholders are 'basically a wash.' GSU Brief at 125.

GSU argues that the allocation of the margins or profits is a policy issue to be decided from an equitable basis, as opposed to an issue resolved on the basis of factors such those listed in Docket No. 9945. GSU Brief at 124. True, the Examiners' Report in Docket No. 9945 recognized that the allocation of profits was indeed a policy decision. The ALJ there, however, also found that the allocation must be based on the record evidence in the case. Docket No. 9945, 18 P.U.C. BULL. at 286. Therefore, the ALJ in this proceeding must determine if there is sufficient record evidence on the six factors in Docket No. 9945 in resolving whether the adder should be treated as reconcilable.

TIEC cites two proceedings prior to Docket No. 9945, Docket Nos. 8425 and 9300, in support of its position that the adders should be treated as reconcilable. In Docket No. 8425, HL&P's off-system sales profits occurring during its reconciliation period were reconciled. The Commission found:

97. The Company's profits from off-system sales received during the reconciliation period are generated, in large part, by plant paid for by the Company's ratepayers. In the Company's last rate case, Docket No. 6765, the Commission did not determine that profits from off-system sales should be reflected in base rates. The profits received during the reconciliation period in the amount of $9,191,554 should be reconciled.

***40** *Application of Houston Lighting & Power for Authority to Change Rates*, Docket No. 8425, Finding of Fact No. 97, 16 P.U.C. BULL. 2199, 2721 (June 20, 1990). In Docket No. 9300, TU Electric's last rate case, TU Electric was required to include its test year off-system sales profit as miscellaneous revenue in calculating its revenue requirement. *Application of Texas Utilities Electric Company for Authority to Change Rates*, Docket No. 9300, Finding of Fact No. 230, 17 P.U.C. BULL. 2057, 2872 (Sept. 21, 1991).

TIEC also analyzed the evidence presented in this case under the six factors listed in Docket No. 9945. As for the first factor, there is no dispute that the off-system sales are made possible by plants that the ratepayers have paid for or are paying for now. Tr. 3768-3769; TIEC Ex. 10 at 29-30; Calvert Ex. 24 at 9. With respect to the second factor, there is no evidence indicating the necessity of an incentive to encourage GSU to engage in off-system sales which occurred during the reconciliation period.

The third factor listed in Docket No. 9945 involved the proposed allocation's impact on the utility's financial strength. As stated above, the Commission found in Docket No. 9945 that EPE's poor financial condition was one of the most compelling reasons for allocating a portion of the margins or profits from the off-system sales to the shareholders. Docket No. 9945, 18 P.U.C. BULL. at 579. There is no evidence that GSU is suffering under the same or similar dire situation as EPE. In fact, GSU has stated that off-system sales are not a significant portion of its business. GSU Ex. 97 at 57.

As for the fourth factor, except to the extent that it affects GSU's financial condition, whether dividends are paid or not paid to shareholders is not significant in determining the appropriate allocation of the profits between the ratepayers and shareholders. Docket No. 9945, 18 P.U.C. BULL. at 293. Although no dividends were paid to GSU's shareholders during the reconciliation period,[FN16] there is no evidence as to if or how that omission has affected GSU's financial condition.

With regard to the fifth factor concerning the burdens borne by the ratepayers, TIEC correctly notes that there is no evidence regarding ratepayer burdens resulting from GSU's off-system sales. Finally, with respect to the factor addressing the advantages enjoyed by shareholders, to the extent that the profits are not treated as reconcilable, TIEC argues that GSU will receive a windfall for simply fulfilling its obligation to its ratepayers. TIEC Brief at 23-24.

Commission precedent concerning the reconcilable treatment of off-system sales adders and the appropriate allocation, if any, between ratepayers and shareholders is mixed. The Commission has decided these issues on a case-by-case basis, which the ALJ believes is entirely appropriate given the fact-based standards set out in Docket No. 9945. The ALJ finds that TIEC's analysis of the evidence under those standards is correct.

41 Calvert and TIEC also correctly contend that there is no credible evidentiary basis for concluding that a portion of the off-system sales adders should be allocated to shareholders. GSU's current base rates are based upon the test year ending in September 1988. During that test year, GSU's off-system sales totalled slightly over 1.2 million MWH, which is approximately four times the current annual level of off-system sales. Incremental O&M was not removed from the test year O&M amount. Tr. at 8780-8781. Therefore, GSU's test year O&M included approximately $720,000 per year of incremental O&M for off-system sales. This is approximately $540,000 per year more than the current level. Calvert Ex. 24 at 12.

The ALJ is persuaded that GSU's current base rates include more than sufficient incremental O&M expense to cover the off-system sales which occurred during the reconciliation period. The ALJ therefore declines to reduce the amount of the adders by an additional $551,372 as recommended by TIEC witness Mr. Pollock. For all these reasons, the ALJ recommends that 100 percent of the off-system sales adders from the reconciliation period, or $4,226,075, be treated as reconcilable in this case.

E. River Bend Station Costs

1. General Overview

GSU's River Bend Station (River Bend) is located in West Feliciana Parish, approximately 24 miles north-northwest of Baton Rouge, Louisiana. GSU is the operating agent for River Bend and owns 70 percent of the unit. River Bend is a boiling water reactor designed by General Electric Company (GE) with a net electrical output of 936 MW. The plant received its operating license from the NRC on November 20, 1985, and has been producing electricity since that time. General Counsel Ex. 5 at 2.

During the reconciliation period, GSU included the following nuclear fuel cost components related to its ownership share of River Bend Unit 1 in FERC Account 518, Nuclear Fuel Expense, in accordance with (1) the description of this account (Part B) in the FERC Uniform System of Accounts, and (2) the treatment of such expenses by the Commission in Docket No. 7195:

1. The amortization or 'burn-up' of the core of 624 nuclear fuel assemblies; 2. The interest on the unamortized balance of the in-core leased nuclear fuel at an average interest rate of 11.53 percent during the majority of the reconciliation period; 3. Payments to the Department of Energy (DOE) for future spent fuel disposal costs at 1 mill per KWH of net River Bend Unit 1 generation; and 4. The amortization ($1.6 million annually over three years beginning July 23, 1988) of accumulated contra-AFUDC on nuclear fuel previously included in rate base, as ordered by the Commission in Docket No. 7195.

GSU Ex. 29 at 14. The amortization of contra-AFUDC on nuclear fuel was completed on July 22, 1991. Therefore, the first three components of nuclear fuel costs listed above - fuel amortization, spent fuel, and interest expense - are treated by GSU as reconcilable fuel costs in this case. *Id.* at 13-14.

42 For the reconciliation period, GSU is requesting that $158,221,970 in nuclear fuel costs be treated as reconcilable. GSU Ex. 29A, Sch. FR.J-3. OPC, Calvert, and the General Counsel recommend certain disallowances related to River Bend's planned and forced outages. Also, OPC makes additional recommendations regarding GSU's documentation of River Bend events.

2. Refueling Outage 2

River Bend Refueling Outage 2 (RFO-2) began on March 15, 1989, and ended on June 8, 1989. RFO-2 was initially scheduled to last for 60 days but actually lasted 85 days. OPC and Calvert recommend disallowances based on alleged imprudent and unreasonable actions by GSU which, in their opinion, delayed completion of RFO-2.

a. Division I Diesel Work

During RFO-2, the critical path[FN17] schedule of the outage was delayed by work done on the Division I diesel generator. Calvert alleges an 11-day delay resulting from GSU's imprudence, while OPC argues that a 2-day delay resulted. GSU contends that any delay in RFO-2 was not the result of its imprudence, and therefore asserts that no disallowance be imposed.

Calvert witness Dr. Jacobs testified that Cooper Industries, the contractor selected by GSU to perform the diesel work for GSU during RFC-2, failed to complete its work on schedule, resulting in a delay of the critical path schedule and an extension of RFO-2. Calvert Ex. 33 at 6. According to Dr. Jacobs, there were approximately 17 days of duration variation in the Division I diesel inspection, 11 days of which were a slip in the critical path schedule. Therefore, he recommended that the replacement power costs associated with 11 days of lost generation be disallowed. Calvert Ex. 33 at 9.

According to GSU's October 9, 1989, Close-Out of Contracted Work documentation regarding Cooper Industries, GSU experienced delays in Cooper's work prior to the beginning of RFO-2 and expended a considerable amount of time and effort to improve Cooper's performance. Calvert Ex. 33, Sch. WRJ-2 at 99891. The document's summary stated that 'the Cooper site management and planning efforts started late and caused a 'never on time' ripple effect throughout most of the outage.' Calvert Ex. 33, Sch. WRJ-2 at 99893. In addition, GSU's RFO-2 Outage History Report attributed the Division I diesel generator inspection delays to the ' contractor's lack of familiarity with GSU procedures.' OPC Ex. 53, Sch. DAS-3 at 13.

OPC witness Mr. David Schlissel also found fault with Cooper's Division I diesel work. OPC Ex. 53 at 22. Citing GSU's outage history report, Mr. Schlissel testified that the completion of the planned Division I diesel generator outage was extended by 11 days to April 14, 1989. Work was scheduled to start on the Division II diesel generator immediately after the completion of the Division I Emergency Core Cooling System (ECCS) test. The Division II diesel generator work did not start until April 16, 1989, however, despite the fact that the ECCS test was completed on April 14, 1989. The duration of the Division II diesel generator work was ultimately extended by 13 days. These delays meant that the Division II ECCS test, which was scheduled to be completed on April 23, 1989, was actually completed on May 12, 1989, 19 days later than scheduled. *Id.* at 23-24. GSU's outage history report for RFO-2 listed spare parts qualification, QA documentation, tagging, and repairs as contributing to the delays in the planned diesel generator related work.

***43** River Bend has a safety tagging system to prevent the operation of plant equipment when such could cause personal injury or equipment damage. This system requires maintenance personnel to obtain a clearance to make repairs, design changes, and perform routine maintenance on plant equipment. Repeated violations of the safety tagging procedure were experienced during the first month of RFO-2. Several of these equipment tagging violations were committed by employees of Cooper Industries. OPC Ex. 53 at 26.

On April 13, 1989, GSU issued a stop work directive which halted work by Cooper until its personnel could be retrained and an assessment of Cooper's work could be performed. Procedures were established to ensure that similar tagging violations would not be repeated. The stop work directive was lifted on April 14, 1989. *Id.* at 26-27. Several GSU documents indicate that GSU concluded that a lack of adequate training in GSU's procedures was responsible for the tagging violations. *Id.* at 27-28. NRC Inspection Report No. 89-11 found that GSU failed to take adequate corrective actions to prevent new violations of its tagging system, based on the conclusion that the corrective actions taken by GSU during the first month of RFO-2 failed to determine the extent to which tagging violations existed. *Id.* at 29.

Due to poor performance, GSU removed Cooper's original project manager from the site during the second refueling outage. The project manager was sometimes late to work, causing him to miss the daily outage management meeting, and was not carrying out his responsibility to maintain the outage schedule. This poor performance required GSU to work with others in the organization to maintain the schedule. *Id*. at 30. Although GSU found that Cooper's physical work was performed in a highly professional manner, it also rated Cooper's field supervision as poor. Mr. Schlissel asserted that, at a minimum, the completion of the Division II diesel generator inspections and maintenance work was delayed at least two days due to mismanagement by Cooper. OPC Ex. 53 at 33-34.

Although it acknowledges the necessity to remove Cooper's original project manager from the site during the outage, GSU does not agree that the problems experienced with Cooper's performance caused the Division I diesel delay. GSU witness Mr. Peter Freehill agreed that the critical path during RFO-2 was delayed by the diesel generator work. Under such circumstances, the Division I diesel generator inspections and ECCS test became the critical path item. The Division I ECCS test was completed on April 14, 1989, eleven days later than the scheduled outage for the Division I diesel generator. GSU Ex. 81 at 7.

Mr. Freehill contends that the start of the Division I ECCS test was delayed by the discovery of broken manifold bolts during inspection of the Division I diesel generator which had to be repaired before the diesel was put back into service. The bolts were removed and replaced, and an intake manifold brace was designed, fabricated, and installed to reduce the stress on the bolts. According to Mr. Freehill, this repair work delayed the completion of the diesel work 260 hours, or 10.83 days. *Id*. at 8; GSU Ex. 82.

***44** Mr. Freehill criticizes Dr. Jacobs' and Mr. Schlissel's conclusion that the delay in the start of the Division I ECCS test was due to Cooper's poor performance. He contends the Division II work could not begin until the Division I diesel generator was operable because the NRC requires that at least one diesel generator be operable even during an outage. During the time the stop work directive was in effect, the Division I ECCS test was being performed. The test began on April 11 and was completed on April 14, 1989. Mr. Freehill argues that the two-day interval between the end of the Division I ECCS test and the beginning of the work on the Division II diesel generator was not a 'delay.' Rather, he contends the lapse in time was normal and expected because the necessary paperwork from the Division I work first had to be closed out and the Division I diesel generator had to be returned to service prior to work beginning on the Division II diesel generator. *Id*. at 9. Mr. Freehill remains steadfast in his position that the primary cause for delay in the completion of the Division I diesel generator work was the discovery during inspection and subsequent repair of the broken manifold bolts. He believes that this 'unanticipated' problem alone accounted for almost the entire eleven-day delay. *Id*. at 10.

GSU witness Mr. James Deddens contends that GSU did not know the condition of the equipment prior to the outage. The contract with Cooper was an inspection work scope contract which required the contractor to examine the engines and generators to determine their condition. The discovery of the broken intake manifold bolts was a normal consequence of diesel operation. Mr. Deddens contends that, contrary to OPC's and Calvert's testimony, GSU reviewed Cooper's work and found no violations. GSU Ex. 80 at 15.

The testimony of OPC witness Mr. Schlissel and Calvert witness Dr. Jacobs is the most persuasive on this issue. GSU's own documents state that delays in the Division I diesel work were attributable to Cooper's lack of familiarity with GSU's procedures. True, the outage history report for RFO-2 indicates that GSU had to repair an intake manifold crack and install intake manifold braces. OPC Ex. 53, Sch. DAS-3 at 9. However, the schedule variance for RFO-2 lists Cooper's problems as the reason for the delay, not the manifold bolt repairs. *Id*. at 13. GSU's repudiation of the accuracy of the statements in its own outage history report is not credible. OPC Ex. 58 and 59; Tr. 3107; Tr. 3112.

The ALJ recommends a disallowance for the delay in work performed on the Division I diesel generator by Cooper. Dr. Jacobs recommended a disallowance for 11 days of lost generation, while Mr. Schlissel found a two-day delay.

Dr. Jacobs' recommended 11-day delay is based on the outage history report for RFO-2, which identified approximately 17 days of duration variation in the Division I diesel generator inspection. Eleven of those 17 days were a slip in the critical path. Calvert Ex. 33 at 9.

***45** Mr. Schlissel's calculation of the delay is somewhat more obtuse. Tr. 2474-2476; OPC Ex. 53 at 48. He quantified the delay by paralleling critical paths, determining that the Division I and II diesel generator work could have been completed two days earlier than May 12, 1989, or May 10, 1989. He recognized, however, that the Commission could find a greater delay based on the testimony of other witnesses, presumably Dr. Jacobs. Tr. 2475-2476.

The ALJ recommends a disallowance for the delay in the Division I diesel work, as recommended by Dr. Jacobs and based on the 11-day delay in the critical path cited in the outage history report. This recommendation results in a disallowance of $1,584,012 on a total company basis. Calvert Ex. 33B.

b. Valve Testing and Repairs

After the Division I diesel generator work was finished on April 14, 1989, the reactor water cleanup system (RWCU) work was extended from 12 to 35 days. Consequently, this effort became the critical path and remained so until May 14, 1989. OPC Ex. 53 at 34; Sch. DAS-3 at 4. Mr. Schlissel argues that GSU failed to identify the root cause of the problems which led to the valve repairs and retests, recommending a disallowance for a two-day delay in RFO-2.

The work which extended the RWCU outage involved a series of valve repairs and retests. Forty-eight of 208 valves tested failed the Local Leak Rate Test (LLRT). The LLRT measures how much a valve leaks when it is closed. If there is too much leakage, the valve must be repaired and retested. Because GSU believed that the LLRT failures were normal equipment malfunctions due to wear and expected degradation, it did not generate any analyses, evaluations, or root costs studies for any of the valves which failed their initial LLRTs. *Id.* at 35.

Although Stone & Webster Corporation (Stone & Webster) had overall responsibility for the local leak rate testing, Anchor Darling Valve Company (Anchor Darling) was the contractor for the valve repairs. *Id.* at 38. Mr. Schlissel contends that Anchor Darling mismanaged the valve repair program, resulting in repeated safety tagging violations which eventually led to the issuance of a stop work directive on April 13, 1989. GSU had to repair and retest a number of valves previously repaired by Anchor Darling, and eventually transferred the valve repair work to Stone & Webster in late April and early May 1989. Based on this experience, GSU recommended that Anchor Darling not be rehired in the same capacity for future River Bend activities. *Id.* at 39.

Six of the safety tagging procedure violations occurring during the first month of the refueling outage were committed by Anchor Darling personnel. The stop work directive issued on April 13, 1989, was in effect against Anchor Darling until its personnel could be retrained on GSU's safety tagging program, an assessment of all existing Anchor Darling work packages could be performed, and procedures established to ensure that similar tagging violations would not be repeated in the future. The stop work directive remained in place until April 14, 1989. *Id.* at 40.

***46** GSU notified Anchor Darling of its problems with the latter's performance on April 13, 1989. OPC Ex. 53, Sch. DAS-9. Afterwards, GSU sought compensation concessions as indemnification for Anchor Darling's performance during the outage. OPC Ex. 53, Sch. DAS-11. Also, GSU initially withheld payment of approximately $1 million billed by Anchor Darling for valve repair work completed during the outage. OPC Ex. 53 at 39. GSU and Anchor Darling ultimately reached a settlement of the dispute in the fall of 1989. Under the settlement, GSU paid approximately $600,000 of the disputed $1 million payment to Anchor Darling. *Id.* at 43.

In support of his recommended disallowance predicated on an imprudent two-day delay, Mr. Schlissel cited several GSU documents demonstrating GSU's dissatisfaction with Anchor Darling's performance during the outage. OPC Ex. 53, Sch. DAS-14, DAS-15, DAS-16, DAS-17. In a document reflecting GSU's final evaluation of Anchor Darling's work during RFO-2, it rated Anchor Darling's performance as poor in the area of management/supervision and cooperation. *Id.*, Sch. DAS-18.

According to Mr. Freehill, the valves at issue could not be worked on 24 hours a day. Consequently, putting more personnel on the valve job would not have solved the problem because physical size limitations restricted the number of people who could work in that area. GSU Ex. 81 at 15-17. Mr. Freehill also disputes Mr. Schlissel's allegation of mismanagement of Anchor Darling. He contends that the stop work directive in effect on April 13 and April 14, 1989, did not delay the valve work because the RWCU work could not begin until the Division I ECCS test was completed. The Division I ECCS test was finished on April 14, 1989, the same date that the stop work directive was lifted. The LLRT for the RWCU valves began on April 14, 1989, the first date such work could begin. *Id.* at 18. Additionally, Mr. Freehill argues that while GSU retested and repaired a number of valves worked on by Anchor Darling, GSU's work did not delay the outage because the RWCU outage had already ended by the time that GSU retested and repaired the valves. The transfer of repair work from Anchor Darling to Stone & Webster also did not delay the RFO-2 work, but instead permitted the work to be completed more quickly. Finally, while it is true GSU recommended that Anchor Darling not be rehired in the same capacity on future River Bend outages, that recommendation had no impact on the second refueling outage schedule. *Id.* at 19.

While it appears that Anchor Darling's performance may have been less than stellar, the credible evidence supports the conclusion that GSU was able to rework and retest the valves in time to prevent further delay in the critical path of RFO-2. The ALJ recommends that Mr. Schlissel's proposed disallowance not be adopted.

c. Preferred Station 'B' Transformer Fire

The A and B preferred transformers provide voltage to loads at the plant when the plant is shut down. GSU considers the transformers to be non-safety related components. Tr. 3368-3369.

***47** On May 29, 1989, near the scheduled end of the second refueling outage, the B preferred transformer was energized following routine maintenance, exploded, and caught on fire, resulting in a forced outage until the installation of a replacement transformer. Calvert Ex. 33 at 9. This forced outage began at the end of the second refueling outage on June 8, 1989, and ended on June 24, 1989. It effectively resulted in a 16-day extension of the second refueling outage. Calvert witness Dr. Jacobs recommends that the replacement power cost associated with these 16 days of lost generation be disallowed.

Dr. Jacobs claims that the fire in the B preferred transformer resulted from GSU's imprudent conduct because prior problems with the A preferred transformer should have alerted GSU to the potential problem with the B preferred transformer. He alleges that the prior problems with the A preferred transformer were relevant because the A preferred transformer is capable of serving the same load as the B preferred transformer. Stated another way, any problems with the A preferred transformer that were due to design or O&M practices would likely be a problem with the B preferred transformer as well. *Id.* at 10; Tr. 2323.

The A preferred transformer initially failed on June 14, 1985. The transformer apparently experienced a number of low-side faults which probably caused progressive winding distortion that finally resulted in the failure. Calvert Ex. 33, Sch. WRJ-3 at 145964. Low-side faults, also called through faults, are short circuits on the low voltage side of the transformer. Repeated excessive current associated with these faults will cause magnetic forces to act internally on the transformer windings, causing the windings to deform or deflect. Calvert Ex. 33 at 10. GSU rebuttal witness Mr. Graham testified that GSU tested the B preferred transformer in 1985 because of the failure of the A preferred transformer, and also conducted a Doble test on March 25, 1986. According to Mr. Graham, those tests did not indicate degradation, negative trends, or any other problem with the transformers. GSU Ex. 84 at 15.

Early in RFO-2, oil samples taken from the A preferred transformer indicated a problem with that transformer. The presence of dissolved combustion product gases in the oil sample indicates an internal arcing in the transformer. Calvert Ex. 33 at 10. After GSU discovered the dissolved gases in the A preferred transformer, it conducted a Doble test. The Doble test determines if there was distortion of the insulation or the windings internal to the transformer. The Doble test performed on the A preferred transformer showed that high excitation currents existed and that the transformer had deteriorated. *Id.* at 11; Tr. 3216. The cause of this deterioration was most likely low-side or secondary faults from the auxiliary boiler. Tr. 3219.

The A preferred transformer was then sent off-site for repairs. Tr. 3216. In addition, GSU decided to provide a separate power source for the auxiliary boiler, which was believed to be the source of the low-side or through faults to the transformer. By removing the auxiliary boiler feed from the A and B preferred transformers, the number of through faults would be significantly reduced. Calvert Ex. 33 at 11-12; Tr. 2318-2319.

48 In an April 7, 1989 memorandum, Mr. Penner, a principal engineer with GSU's Beaumont engineering group whose responsibilities included inspection of transformer failures, concluded that the failure of the A preferred transformer was due to the inability of the transformer to handle the repeated through faults to which it had been subjected. Calvert Ex. 33, Sch. WRJ-6; Tr. 3313. In Calvert witness Dr. Jacobs' opinion, if the A preferred transformer had suffered winding or insulation distortion as a result of the low-side faults, it was likely that the B transformer would have been subjected to the same kinds of problems.

Prior to the May 29, 1989 fire and explosion in the B preferred transformer, the B preferred transformer energized and tripped due to secondary cable faults on two occasions: May 2, 1989, and May 23, 1989. These secondary cable faults were low-side or through faults. Calvert Ex. 33 at 12. GSU performed a Doble test on the B preferred transformer on May 9, 1989, following the trip on May 2, 1989. Mr. Graham claims that the oil sample and Doble test revealed normal conditions. GSU Ex. 84 at 16. Oil samples were again taken following the May 23, 1989 trip to determine the presence of gases, but the results were once again negative. GSU decided that an additional Doble test was not warranted because the previous Doble test performed on May 9, 1989, and oil sample results were normal.[FN18]

United Engineers & Constructors, Inc. (UEC) prepared an analysis of the B preferred transformer failure for GSU. Calvert Ex. 33, Sch. WRJ-7. According to the executive summary of UEC's failure analysis, the B preferred transformer suffered mechanical damage which was caused by excessive axial short circuit forces. Calvert Ex. 33, Sch. WRJ-7 at 96364. Additionally, Mr. Penner stated that the auxiliary boiler had been fed by the A and B preferred transformers. He concluded that the relatively frequent faults in the auxiliary boiler contributed to the transformer failures. Calvert Ex. 33, Sch. WRJ-8.

While both the A and B preferred transformers were capable of supplying the auxiliary boiler and thus the same load, GSU rebuttal witness Mr. Graham stated that the A preferred transformer supplied the boiler the vast majority of the time. Further, because the A and B preferred transformers were in 'different service' with respect to the auxiliary boiler, he believes that the possibility of a failure in the B preferred transformer was reduced.

If GSU could prove that the A and B preferred transformers were not in identical service, then such proof would undermine Dr. Jacobs' claim that GSU should have known that the problems with the A preferred transformer indicated that the B preferred transformer was also at risk. The documentation generated by both Mr. Penner and UEC refer to the fact that the B preferred transformer was in auxiliary boiler service. These two documents were prepared in July and August 1989, a couple of months following the B preferred transformer fire. GSU attempted to rebut Mr. Penner's and UEC's reports, but the credible evidence supports Dr. Jacobs' conclusions regarding the service of the A and B preferred transformers. Mr. Graham's attempts on the stand to rehabilitate GSU's position were not sufficient to persuade the ALJ that Mr. Penner, a GSU engineer assigned to transformer inspections, and UEC, the company hired by GSU to conduct a failure analysis on the B preferred transformer, would both be wrong. In fact, in response to Request for Information (RFI) CIT-13-0041-a, GSU responded that the transformers were in the same type of service. Tr. 3224.

49 Based on the credible evidence, the ALJ finds that the prior problems with the A preferred transformer should have alerted GSU to the potential problem with the B preferred transformer. The 16-day delay was a result of imprudence. Therefore, Dr. Jacob's recommended disallowance of $2,245,911 on a total company basis for the resulting 16-day delay should be adopted.

3. Refueling Outage 3

River Bend Refueling Outage 3 (RFO-3) began on September 29, 1990, and ended on December 4, 1990. The outage was scheduled to last for 58 days but actually lasted 66 days. The purpose of the outage was to refuel the reactor in preparation for the fourth cycle of operation at River Bend. There were several delays in completing RFO-3 which the intervenors claim are attributable to imprudent or unreasonable actions by GSU. Specifically, OPC and Calvert claim that the alignment of the diesel generator out-of-phase with the grid, the diesel repairs associated with the water leak, and the diesel generator exhaust fire were all associated with imprudent or unreasonable actions on the part of GSU.

a. Out-of-Phase Synchronization of Division II Diesel Generator

GSU's outage history report for RFO-3 states that a six-day delay of the outage was due to the synchronization of the Division II diesel generator out-of-phase to the grid. OPC Ex. 53 at 53. OPC witness Mr. Schlissel and Calvert witness Dr. Jacobs recommend a disallowance for the six-day delay. General Counsel witness Chester Oberg, however, does not recommend a disallowance with respect to this event. General Counsel Ex. 5 at 6.

The function of the Division II diesel generator is to provide power to the Division II equipment when off-site power is lost. During the outage, either the Division I or the Division II diesel generator must be operable. At the beginning of River Bend's third refueling outage, the Division I diesel generator was operable while preventative maintenance was performed on the Division II diesel generator. Once the Division II diesel generator was tested and declared operable, preventative maintenance was scheduled to begin on the Division I diesel generator. OPC Ex. 53 at 55.

On October 21, 1990, the Division II diesel generator was undergoing post-maintenance testing. During this testing, the generator was scheduled to be synchronized to the plant's electrical grid to verify that its load carrying capability had not been degraded. The process of synchronizing the diesel generator to the grid was performed by a Unit Operator, who manually closed the diesel generator's output breaker when the diesel generator and the grid voltages were in phase. In synchronizing the Division II diesel generator, however, the Unit Operator mistakenly closed the diesel generator output breaker with the generator voltage out-of-phase with that of the grid.

River Bend's Independent Safety Engineering Group (ISEG) prepared an analysis of the out-of-phase synchronization of the Division II diesel generator. OPC Ex. 53, Sch. DAS-21. Conceptualized by the NRC after the Three Mile Island accident, ISEG's general function is to provide independent engineering assessments of matters that are important to nuclear plant safety.

***50** According to ISEG, the event ' was solely due to operator inattentiveness and failure to follow procedure.' *Id.* at 92120. It concluded that other factors such as inadequate training, experience, and procedures did not contribute to the incident. The operator admitted that he failed to check his synchroscope before closing the output breaker as the procedures required. The operator had been momentarily distracted when closing the output breaker, but did not feel that the distraction contributed to his failure to recheck his synchroscope. According to ISEG's analysis, if synchronization check devices had been installed at River Bend, the operator could not have closed the diesel generator output breaker at the incorrect moment. *Id.* at 92120.

Several years ago, in August 1985, ISEG examined River Bend's diesel generator synchronization circuitry and concluded that it was possible to synchronize the diesel generator and the grid out-of-phase. The synchronization of the diesel generator and the grid occurs at least 36 times per year; although the procedure is simple, ISEG felt that the potential existed to damage a diesel generator. OPC Ex. 53, Sch. DAS-22 at 135767. As a result, ISEG recommended in 1985 that a synchronization check device be installed in the circuit breaker control circuits to prevent the breaker from connecting two out-of-phase voltages. *Id.* at 135767.

ISEG's Special Analysis report (SA 90-011) indicated that the recommendation made by ISEG in 1985 was made in the form of an Engineering Evaluation and Request (EEAR). An EEAR requests the Engineering Department to review a recommendation to determine whether it should be implemented. Tr. 3249. The EEAR was approved by the plant manager and the modification recommended for completion by River Bend's first refueling outage. However, the EEAR was not presented to the Work Scope Committee because Design Engineering characterized the requested EEAR as a 'betterment.' Therefore, if ISEG wanted the synchronization check device installed, it would have to support the modification before the Work Scope Committee itself. Without the support of Design Engineering, ISEG felt that the issue was dead and did not pursue the matter. Calvert Ex. 33, Sch. WRJ-10 at 87330. According to Calvert witness Dr. Jacobs, ISEG's recommendation to install a synchronization check device should have been pursued and presented to the Work Scope Committee, and the plant manager should have assured that the request was carried out. He found fault with the characterization of an ISEG recommendation as a 'betterment.' In his opinion, GSU's decision to decline to take it before the appropriate management committee was unreasonable. Calvert Ex. 33 at 18.

GSU contends that the operator's failure to perform the synchronization of the Division II diesel generator to the grid was a result of human error and not an imprudent or unreasonable act on the part of River Bend management. GSU Ex. 84 at 4. GSU witness Mr. Graham maintains that the synchronization check devices constituted a betterment or enhancement, and were not necessary for the safe operation of the plant. He believes the risk of an out-of-phase synchronization was acceptable. *Id.* at 4.

***51** Mr. Graham gave the following reasons for not installing the synchronization check device: (1) the devices were not required for safe, reliable operation of the plant; (2) River Bend operators were highly trained and skilled to perform this simple activity properly; (3) the probability of an out-of-phase event was low; (4) other modifications and plant betterments had a much higher priority based on need or regulatory requirements; and (5) there was a concern that installation of the devices may cause the operator to become too dependent on the device and therefore become complacent about alertly performing the activity. *Id.* at 5. To support his argument, Mr. Graham conducted a survey to determine whether other plants had such check devices. Of eleven units, only two had check devices for their diesel generators; one of those two units had three diesel generators, but only used the check device on two of its three generators.

The failure to perform the synchronization of the Division II diesel generator to the grid was an isolated error which resulted in a delay to the third refueling outage. ISEG did not find that the quality of training, experience or procedure contributed to the event. Indeed, there is no credible evidence which would suggest that is the case. Any proposed disallowance associated with this event would therefore be based on GSU's failure to consider and/or implement ISEG's earlier recommendation that synchronization check devices be installed.

The ALJ recommends that a disallowance related to this event not be imposed. While out-of-phase synchronizations may occur from time to time, it was not imprudent for GSU to choose not to evaluate the installation of synchronization check devices based on ISEG's earlier analysis for three reasons: (1) the devices are not required for the safe operation of the plant, (2) the probability of an out-of-phase event is very low, and (3) the operator must perform the function properly regardless of whether a synchronization check device is installed.

b. Diesel Generator Exhaust Water Jacket Repair

In November 1990, a crack about one and one-half inches long was discovered in the welded connection between the Division II diesel turbo-charger exhaust and the intercooler. According to GSU's preliminary root cause assessment, the intercooler adaptor on Division II had an inferior fit-up in the outboard linear weld between the air box and the inplate, as well as a poor quality weld between the round adaptor and the inplate in the area of the most recent cracking. The root cause of the cracking was traced to a procedural violation which resulted in the application of an undersized weld at the particular location. Calvert Ex. 33 at 19. GSU identified two other contributing causes: (1) the repeated welding done in the area of the crack, which GSU concluded was minor; and (2) the loosening of the U bolts on the combustion air pipe which increased the load on the area. *Id.* at 20.

***52** Calvert witness Dr. Jacobs testified that GSU was responsible for the poorly welded area on the Division II adaptor, even though this quality assurance violation occurred at the factory during the original manufacture of the diesel. He believes the quality assurance program should have prevented this kind of procedural violation. *Id.* at 20. Dr. Jacobs recommends that the replacement power costs for one day of lost nuclear generation be disallowed. Mr. Schlissel also recommends a disallowance for the one-day delay. OPC Ex. 53 at 59-60.

GSU rebuttal witness Mr. Graham testified that the crack, or air leak, was discovered on November 28, 1990, in the duct work between the Division II diesel generator turbo-charger and the intercooler. GSU Ex. 84 at 7-8. Drawings of the weld were reviewed during the diesel's design and installation and were found to be acceptable. The vendor installed the shop weld according to those drawings. However, the gap between the pieces joined by the weld was too wide for the size of the weld specified. Once the weld was made, the gap was hidden from view. The vendor's quality assurance program did not catch the error. *Id.* at 8.

Mr. Graham argues that a quality assurance program cannot guarantee that there will be no defects. The ALJ concurs. The purpose of a quality assurance program is to provide a high level of confidence that defects or deficiencies will be identified and corrected. Based on the credible evidence, the ALJ does not recommend a disallowance related to this event.

c. Diesel Generator Exhaust Fire

On October 20, 1990, a fire occurred in the insulation around the exhaust expansion joint on the Division II diesel generator. The fire occurred following the shutdown of the diesel from a test run to determine unrelated problems with the lubrication system on the diesel. The burning material was removed from the expansion joint and the fire was extinguished. The fire was found to have originated in kraft paper backing to the aluminum outer jacket on the expansion joint. Calvert Ex. 33 at 21.

Calvert witness Dr. Jacobs testified that the design of the diesel exhaust system allowed a portion of the exhaust gas to blow by the expansion joint to eliminate friction and reduce loading on the turbo-charger housing. The design potentially allows 850-degree Fahrenheit exhaust gas to come into contact with the aluminum housing. The diesel had been running unloaded for approximately two and one-half hours prior to the fire. Running the diesel in such an unloaded condition can result in the presence of more unburned fuel in the exhaust gas than is normally present when the diesel is run under load. *Id.* at 21.

Dr. Jacobs argues that the diesel generator fire was the result of GSU's imprudent failure to consider the possibility of hot exhaust gases coming into direct contact with the paper-backed jacketing material. This, in his opinion, was an engineering error. *Id.* at 22. GSU's Condition Report CR #90-0963 stated that the exhaust blow-by feature was not considered in the selection of jacketing materials. Calvert Ex. 33, Sch. WRJ-12. The original design of the expansion joint did not allow direct contact between the hot blow-by exhaust gas and the flammable insulation materials; a subsequent design change, however, covered the expansion joint with insulation. Dr. Jacobs recommends that the repair and replacement cost for lost generation with regard to the diesel fire be disallowed. This would result in a delay disallowance of approximately two days. Calvert Ex. 33 at 22.

***53** GSU witness Mr. Freehill testified on rebuttal that the design change was installed on both diesels in November 1984 when the original expansion joint was replaced with a slip joint. The slip joint was intended to eliminate an overstress problem discovered during start-up testing. Mr. Freehill believes that Dr. Jacobs' position imposes a standard of perfection on GSU, and that the real test of whether management had performed reasonably lies in GSU's operating statistics for River Bend. GSU Ex. 81 at 20.

The ALJ concurs with Dr. Jacobs that a disallowance for the lost generation associated with approximately two days is appropriate. Although GSU contests the fact that the design change allows exhaust gas to come into contact with flammable materials, the credible evidence indicates the fire was a direct cause of a design change, the consequences of which GSU imprudently failed to consider upon its implementation. This imprudence results in a disallowance of $342,655.

4. Forced Outages/Derates

a. Event No. 89-15 (Reactor Scram 89-01)

River Bend was automatically shut down on February 20, 1989. At the time, River Bend was in start-up from a previous plant outage. During the start-up, a decrease in reactor pressure caused by the opening of large steam line drain valves, without the compensation of in service turbine bypass valves, led to an automatic shutdown - or scram - of the reactor. OPC Ex. 53 at 12.

Main steam line drains are used to remove dense steam from the main steam line during plant operations. The valves isolating these drains are normally open during plant operations and shut during a shutdown. During a reactor startup, the valves are sequentially opened once the reactor reaches a minimum pressure. This process is controlled by General Operating Procedure GOP-001. Calvert Ex. 33 at 25.

Scram 89-01 was the fourth scram at River Bend to occur under similar circumstances during a reactor start-up. GSU's ISEG conducted a root cause analysis of this scram. OPC Ex. 53, Sch. DAS-2. The ISEG report stated that keeping the turbine bypass valves in service during main steam line drain valve manipulations was one of the corrective actions adopted following Scram 86-SU-18 in January 1986. Revision No. 6 of GOP-001 following Scram 86-SU-18 added the following cautionary note: 'If performing a Hot Startup, ensure adequate steam bypass capacity prior to opening drains which could increase steam flow. ' When GOP-001, Revision No. 7 was issued in 1987, however, this cautionary note was revised in a manner that did not require that the turbine bypass valves be in service during steam line drain valve operations. Calvert Ex. 33 at 25. ISEG identified this revision as a programmatic weakness. The duration of the River Bend outage following Scram 89-01 on February 20, 1989, was 38 hours, 55 minutes. Mr. Schlissel and Dr. Jacobs argue that the entire outage was the result of GSU imprudence due to failure to ensure that proper controls were in place to provide adequate procedures for plant operation.

***54** Mr. Graham testified in rebuttal that revisions of procedures are covered by River Bend's quality assurance program. There are over 3000 procedures at River Bend that are reviewed and revised regularly. The procedures are included in a word processing computer data base. Mr. Graham argues that even the best system does not always work perfectly and typographical errors sometimes occur. GSU Ex. 84 at 10-12. Mr. Graham notes that GSU's process is the same as that used at other nuclear power stations, and has been reviewed by the NRC without comment. Mr. Deddens argues that OPC and Calvert were attempting to impose a standard of perfection on GSU in basing their recommended disallowances on a typographical error. GSU Ex. 80 at 5.

The ALJ recommends that the additional fuel costs resulting from the 38 hours and 55 minutes of forced outage be disallowed as recommended by Calvert. Calvert Ex. 33B. The deletion of instructions from GOP-001, Revision No. 7 caused the reactor pressure transient which resulted in Scram 89-01. Calvert Ex. 33, Sch. WRJ-13 at 81764. This was not a mere typographical error, as alleged by GSU. Scram 89-01 was, in fact, the fourth scram to occur under similar circumstances. Had GOP-001 not been improperly revised, the scram and ensuing delay could have been prevented. This results in a disallowance of $153,489 on a total company basis.

b. Event Nos. 89-24 and 89-25 (O-rings)

On June 24, 1989 and June 29, 1989, River Bend was taken out of service to repair Electro-Hydraulic Control (EHC) oil leaks on the No. 2 and No. 3 turbine control valves. Modern steam turbines are controlled by an electro-hydraulic control system. This system uses a combination of electrical components and a high pressure hydraulic system to control and operate the various turbine control, stop, and intercept valves that regulate the flow of steam to the turbine. EHC oil is the hydraulic fluid utilized in the system. Calvert Ex. 33 at 28.

The use of incorrect o-ring seals in the electro-hydraulic system caused the EHC oil leaks. According to GSU's Condition Report CR #89-0849, the leaks were traced to failed o-rings:

The Ultra-seal manufacturer (Parker-Hamifin) was contacted to determine the acceptability of the use of a standard o-ring in their '1/4' Ultra-seal fittings. According to Chris Chalmers, the Ultra-seal o-ring cannot be satisfactorily replaced with a standard o-ring. The '1/4' Ultra-seal is machined to accommodate only the Ultra-seal o-rings and the use of standard o-rings could not assure a leak-tight joint.

OPC Ex. 53, Sch. DAS-19 at 4. Therefore, the June 24 and June 29, 1989 events were due to the failure of standard o-rings where proper Ultra-seal #4 o-rings were required. Calvert Ex. 33 at 29; Sch. WRJ-14.

GSU's quality assurance surveillance concluded that the GE craft personnel and supervisors who worked on the turbine control valves during the refueling outage 'should have recognized that these particular Parker-Hamifin fittings required a non-standard o-ring and researched the proper documentation/drawings to verify the correct parts, as was required by their contract.' OPC Ex. 53, Sch. DAS-20 at 3. The quality assurance surveillance also found that the failure to apply the proper Ultra-seal o-ring could have been avoided had reference to the appropriate cite documentation been made. *Id.* at 2.

***55** Following the June 29, 1989 shutdown, GSU evaluated all gaskets and o-rings used in the turbine control valves during 1989. This review found that of six additional connections in the remaining two turbine control valves, three connections had the required Ultra-seal o-rings and three had the incorrect standard o-rings. OPC Ex. 53 at 51. OPC witness Mr. Schlissel argues that GSU's failure to investigate whether improper o-rings had been installed following the June 24, 1989 shutdown was imprudent. He recommends that GSU be liable for the additional costs which resulted from this outage duration of 64 hours. *Id.* at 52.

Calvert witness Dr. Jacobs also believes that GSU has the responsibility to ensure that station personnel and contractor personnel comply with the applicable procedures and controls to prevent installation of incorrect parts and material. Calvert Ex. 33 at 30. In particular, Dr. Jacobs contends that GSU's decision to restart the unit following the June 24, 1989 outage without verifying that correct Ultra-seal o-rings were installed in all required locations was imprudent. In his opinion, GSU should have inspected all other similar applications of o-ring seals in the manner done following the June 29, 1989 outage. The June 24, 1989 outage had a duration of 8 hours, 9 minutes and resulted in 10,619 megawatt hours of lost nuclear generation; the June 29, 1989 outage had a duration of 56 hours, 33 minutes and resulted in 58,531 megawatts of lost nuclear generation. *Id.* at 30. Dr. Jacobs recommends that the additional fuel costs resulting from both these outages be disallowed.

GSU witness Mr. Graham testified that these two forced outages resulted from the failure of contract personnel to follow prescribed procedures, not from any imprudent action on the part of River Bend management. GSU Ex. 84 at 12. He stated that the contractor was contractually required to follow the applicable procedures and use replacement parts that were prescribed by approved drawings and manuals, while contractor personnel were required to receive training on station procedures. A project engineer was assigned to work closely with the contractor to assist him in following the applicable procedures and to help resolve any problems. According to Mr. Graham, no additional inspections were performed after the first oil leak was discovered on June 24, 1989, because River Bend management decided that a single failure alone did not warrant additional inspections. After the second leak, management decided to perform additional inspections. Mr. Graham argues that both the original decision not to inspect, and the subsequent decision to inspect, were reasonable, based on the facts known at the time. *Id.* at 14. In Mr. Graham's opinion, River Bend management took the appropriate reasonable and prudent actions with regard to this contractor. *Id.* at 12.

The ALJ recommends that a delay disallowance of approximately 64 hours be imposed for these two events, based on the recommendations of Dr. Jacobs and Mr. Schlissel. Even GSU concluded that the failure to use the correct O-rings could have been avoided had GE personnel followed the correct procedures. The failure to use correct O-rings was imprudent. GSU must bear consequences of such imprudence. This results in a disallowance of $400,330 on a total company basis. Calvert Ex. 33B.

***56** *c. Event No. 90-68 (Scram During Turbine Testing)*

On December 12, 1990, a reactor scram occurred during performance of the weekly turbine overspeed operability test. This scram resulted from a turbine controlled valve fast closure signal, which arose from an electro-hydraulic trip system pressure transient occurring during surveillance testing of the combined intercept valve. Calvert Ex. 33 at 31. Calvert witness Dr. Jacobs testified that the root cause of this event was an electro-hydraulic trip system pressure transient which occurred during weekly turbine testing. As air is trapped within the system and compressed, a large drop in the electro-hydraulic trip system pressure occurs, allowing the disk dump valve of the other turbine steam valves to release. *Id.* at 31. To prevent reoccurrence of this event, GSU has installed orifices in the electro-hydraulic trip system hydraulic fluid supply lines in all the turbine steam valves.

Dr. Jacobs believes that this reactor scram resulted from GSU's imprudence for two reasons: (1) similar events had occurred on at least four prior occasions, and (2) corrective actions implemented by GSU following those events were insufficient to correct the problem. Dr. Jacobs bases his imprudence recommendation on GE's identification of corrective action approximately eight years earlier. *Id.* at 32.

GSU's Condition Report CR #90-1226 about the event stated:

Consultations with General Electric revealed an industrial problem on some LSTG systems with a control valve pac shutoff valve, different than that installed at River Bend, as experiencing severe 'ETS' pressure transients sufficient to trip units off-line as a result of CIV testing. Though the shutoff valve model was sited [sic] as a contributor to the GE described problem, it is believed that the corrective action taken in the GE Engineering Change Notice T352-415, to install orifices in the ETS supply line, would be applicable corrective action to the River Bend case also since the same scenario as described in the ECN is generated. As a corrective action to prevent recurrence, the orifices recommended in the GE ECN were installed under MR90-0149 (MWO R143210).

Calvert Ex. 33, Sch. WRJ-15 at 41952-41953. In addition, GSU's Operating Experience Report OER 91-001 concluded:

Discussion with the main turbine system engineer revealed that the on site GE-LSTG representative suggested the implementation of the P-Port Orifice modification during RF-3. He did not feel he had adequate justification to process a Modification Request through the Work Scope Committee for implementation during RF-3. The shutoff valves utilized at RBS are an older GE design. These valves are orificed such that normal operation of the EHC system should continuously vent non condensibles from their control pacs (See Figure 1). GE's corporate position was that orificing of the ETS fluid supply to the FAS valves should not be required at RBS because air entrapment was not considered to be a problem with this design.

***57** Calvert Ex. 33, Sch. WRJ-16 at 81873.

Dr. Jacobs testified that Event 90-68 resulted in an outage of 103 hours 41 minutes and a loss of 112,780 MWE of nuclear generation. He recommends that the additional fuel costs resulting from this outage be disallowed. Calvert Ex. 33 at 33.

GSU witness Mr. Graham testified on rebuttal that prior to Event 90-68, spurious movement of more than one combined intercept valve (CIV) was noted while testing. GSU investigated each of these events but was unable to find the cause. While a similar problem had been detected in 1982, the turbine vendor, GE, concluded that River Bend did not have that problem. In response to the note in OER 91-001 stating that a GE LSTG representative may have suggested the change, Mr. Graham countered that the conversation did not equate to an official GE recommendation and that GE never brought such to the attention of GSU's management. GSU Ex. 84 at 20. Mr. Graham believes that River Bend pursued reasonable corrective action based on the information that was available at the time and the ALJ concurs, and therefore no disallowance is recommended for this event.

d. High Temperature in the Steam Tunnel

General Counsel witness Mr. Oberg testified that a reduction in available power to 590 MW was caused by high temperature in the steam tunnels. In his opinion, the root cause of this power reduction was personnel error resulting in imprudently incurred costs. General Counsel Ex. 5 at 9. GSU witness Mr. Graham agrees that the root cause of this event was personnel error. He testified that 'someone inadvertently bumping the damper while performing a walkdown or job in the area' was most likely the cause of this event. GSU Ex. 84 at 23-24. In response to this event, GSU changed the start-up procedure to require a check of the damper position by operations personnel after everyone else completed work or inspection in the steam tunnel. Mr. Graham claims that this event was not the result of imprudence by GSU. The ALJ concurs.

e. Feedwater Heater High Level Dump Valve Short Cycling

General Counsel witness Mr. Oberg also recommends a disallowance as a result of deratings classified as 'Feedwater Heater High Level Dump Valve Short Cycling' events. This type of derating first occurred in 1989. It is also listed in each month, except for those involving outages, for the remainder of the reconciliation period. 'Feedwater Heater High Level Dump Valve Short Cycling' is a catchall derating event for a group of valves that have been leaking during the operating period. While each valve reduced the power generated by only a small amount, the combination of all the leaks made the loss in plant efficiency quite significant, due to the extended time of the derating. General Counsel Ex. 5 at 9-10. These deratings resulted in a loss of 160,073 MWH. Using the average cost of GSU purchased power of $20.90/MWH, Mr. Oberg recommended a disallowance of $3,345,525.70. *Id.* at 10.

***58** GSU witness Mr. Graham explained that the losses designated as 'Feedwater Heater High Level Dump Valve Short Cycling' were caused by various minor problems that developed during the cycle. The heat rate at the beginning of a cycle will generally be better than at the end of a cycle. During refueling outages, GSU performed preventative and corrective maintenance on components that detracted from the heat rate. Mr. Graham contends that it was difficult, even impossible, to positively identify all losses at River Bend. Some losses were judged to be non-recoverable because of the expense it would take to recover them. He also notes that most of these components were located in high radiation fields and could not be worked on during plant operation. GSU Ex. 84 at 23.

The ALJ does not recommend a disallowance related to these losses. The credible evidence shows that these are normal losses which occur over the operating cycle of the plant. The record also indicates GSU took reasonably prudent steps to reduce or eliminate the losses.

5. Calculation of Disallowance

There are two issues to be discussed relating to the calculation of River Bend disallowances:

(1) The appropriate methodology to use in calculating the disallowances and whether interest costs on nuclear fuel should be included in the calculation; and (2) If the Commission were to adopt Mr. Oberg's recommended disallowances, the appropriate methodology to use in calculating those disallowances.

a. Appropriate Methodology and Interest Costs on Nuclear Fuel

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. GSU included the interest component in its calculation, while Calvert and OPC did not.

Calvert witness Dr. Jacobs recommended that the difference in dollars per MWH between the variable nuclear fuel costs and the average system incremental fuel costs be multiplied by the lost generation in MWH to obtain a total reasonable approximation of the cost of lost generation. Calvert Ex. 33 at 33. His recommendation is similar to GSU's methodology, except that GSU used the difference in dollars per MWH between the yearly average costs of nuclear fuel, including the lease interest payments, and the monthly average system incremental fuel costs. By including these lease interest payments, Dr. Jacobs testified that GSU included a fixed cost component in the nuclear cost which is present whether or not the nuclear generation is lost. In his opinion, GSU's methodology overstated the variable cost of nuclear fuel and reduced the differential cost, thus reducing the calculated cost of replacement power. *Id.* at 34.

Mr. Schlissel calculated OPC's proposed disallowances by first determining the number of MWH of River Bend output which were unavailable during each outage as a result of management imprudence, including the MWH from both GSU's 70 percent share of River Bend and the portions of the plant which GSU had contracted to purchase from Cajun Electric. Mr. Schlissel then determined the incremental fuel costs, in dollars per MWH, incurred by GSU during each River Bend outage. He subtracted the River Bend nuclear fuel amortization and spent fuel costs from the system incremental fuel costs figures provided by GSU in Addenda 1 of its Response to RFI CIT-01-051-H. He then calculated the total replacement fuel costs for each outage by multiplying the incremental fuel costs derived above, in dollars per MWH, by the number of MWH of River Bend output which he contended were unavailable as the result of mismanagement. OPC Ex. 53, Sch. DAS-25 at 1. As with Dr. Jacobs, Mr. Schlissel did not include the monthly in-core interest charges because he believed they are fixed rather than variable costs. If the in-core interest charges are included in his recommended fuel cost disallowances, those disallowances would be as shown on Schedule DAS-25 at 2.

***59** GSU witness Mr. Beekman disagrees with the exclusion of nuclear interest costs in Dr. Jacobs' calculation of disallowances. Mr. Beekman's disagreement is based on the premise that the exclusion of interest costs from the calculation of disallowance would result in non-reconcilable treatment, even though the Commission has treated the interest component as a reconcilable fuel cost in every proceeding since the fixed fuel factor was first adopted in 1983. Although GSU records interest payments even when River Bend is not operating, he argues that the amount of the interest payments is variable because it is based on the amount of unburned fuel in the core. GSU Ex. 97 at 56.

Nuclear fuel interest costs are incurred whether the plant generates power or not. They must be included in the two calculations: (1) the costs incurred during an imprudent nuclear outage and (2) the postulated cost that would have occurred had there been no outage. The end result of this double inclusion is that the nuclear fuel interest component drops out of the calculation altogether. If nuclear fuel interest costs are included only in the postulated costs of nuclear generation when there is no outage, as GSU proposed in its calculation, the net effect is to allow GSU to collect those interest expenses twice. Calvert Ex. 33 at 36. The difference in methodology produces a difference of 37 percent in 1989 nuclear fuel costs and a 32 percent difference in the 1990 nuclear fuel costs. *Id.* at 36.

Calvert argues in brief that it has no desire to remove the interest cost as a reconcilable fuel cost or to prevent it from being recovered through the fixed fuel factor. Calvert Reply Brief at 65-66. The issue here is not whether the interest costs are reconcilable, which they are, but whether they are correctly applied in GSU's and the intervenors' calculations. [12] From a purely mathematical perspective, if (1) the object is to compare the cost incurred during an outage with the cost incurred had there been no outage, and (2) the interest component cost accrues regardless of whether there is an outage, then Calvert correctly contends that the interest component must be included in both sides of the equation. Calvert Ex. 33B. The ALJ therefore recommends that the interest component be treated as recommended by Dr. Jacobs and Mr. Schlissel.

There is another issue with regard to the appropriate methodology which has proved very troublesome for the ALJ in calculating the recommended disallowances for the forced outages: the differences, if any, between Dr. Jacobs' and Mr. Schlissel's methodologies.

A review of their exhibits showing their recommended disallowances reveals that Dr. Jacobs and Mr. Schlissel both appropriately accounted for GSU's 70 percent share of River Bend and the effect of the Cajun Electric buyback. Calvert Ex. 33B; OPC Ex. 53, Sch. DAS-25 at 1. Mr. Schlissel subsequently adjusted his disallowances for the Texas jurisdiction, however, while Dr. Jacobs did not. Although the ALJ suspects that this jurisdictional allocation accounts for the majority of the differences in their exhibits, she cannot affirmatively state that it is the only difference. For example, for the forced outages resulting from the use of improper O-rings (Event Nos. 89-24 and 89-25), Dr. Jacobs calculated a loss of 54,242 MWH while Mr. Schlissel found only 46,989 MWH lost due to GSU's mismanagement.

***60** The answer to this dilemma cannot be resolved simply by referring to the testimony in which Dr. Jacobs' and Mr. Schlissel's exhibits were compared because those comparisons were not direct. This is not unusual; the fight is usually between the utility and the intervenors, not between the intervenors themselves. A review of the parties' briefs reveals two contested issues regarding the calculation of River Bend disallowances: (1) the inclusion or exclusion of the interest component and (2) the recalculation of Mr. Oberg's proposed disallowances. The lack of any contest between Dr. Jacobs and Mr. Schlissel leads the ALJ to conclude that any differences between the two exhibits result from the difference in jurisdictional allocation and perhaps to rounding. In any event, the difference apparently was not important enough for the parties to litigate or brief.

The ALJ has recommended adoption of Dr. Jacobs' proposed 11-day disallowance for the delay in the Division I diesel generator work, and his proposed 16-day disallowance for the Preferred Station B transformer fire during RFO-2. Additionally, the ALJ has adopted Dr. Jacobs' proposed 2-day disallowance for the diesel generator exhaust fire during RFO-3. Therefore, the ALJ will also recommend Dr. Jacobs' calculations for forced outage No. 89-15 (improper revision to GOP-001) and Nos. 89-24 and 89-25 (improper O-rings). These disallowances must be adjusted to reflect the Texas jurisdictional share.

b. Recalculation of Mr. Oberg's Proposed Disallowances

If the Commission adopts Mr. Oberg's recommended disallowances, they should be adjusted to reflect the proper calculation of replacement energy, as recommended by GSU rebuttal witness Mr. McLaughlin. In its brief, the General Counsel agreed with this adjustment to Mr. Oberg's calculations. General Counsel Brief at 25. Mr. McLaughlin calculated the replacement energy cost for the two deratings identified by Mr. Oberg during the reconciliation period to be $1,819,794,80. *Id.* at 3; Sch. JAM-2.

6. Documentation

OPC witness Mr. Schlissel testified that GSU's discovery responses to RFIs indicated that it had not maintained copies of a substantial number of critical outage-related documents. OPC Ex. 53 at 17. Although he admits that GSU provided a large number of documents, none of them addressed or quantified the impact of delays experienced during an outage during critical or near critical path activities or identified the root causes of such delays. *Id.* at 19. He claims that GSU rationalized its failure to maintain a copy of the outage progress and status reports from RFO-2 on the contention that the documents rapidly became stale. *Id.* at 20; Sch. DAS-5 at 1. He believes that GSU should have maintained at least one copy of every significant outage document, even if on microfilm.

Mr. Schlissel recommends that the Commission direct GSU to maintain at least one legible copy of the following documents developed and used during River Bend outages:

***61** 1. Outage progress or status reports; 2. Minutes, notes, and summaries of daily outage management and scheduling meetings; and 3. Overall outage schedules and the schedules for critical, near-critical path, and other significant activities.

Not surprisingly, GSU strongly disagrees with Mr. Schlissel's allegation that River Bend does not maintain a substantial number of outage-related documents. GSU Ex. 81 at 10. Mr. Freehill testified that GSU maintains daily outage meeting agendas. The agendas contain each day's critical and near-critical path activities along with a list of open items requiring attention to support critical activities. The agendas also contain critical 'fragnets,' which are detailed schedules of individual work items, and other information pertaining to the day's activities. *Id.* at 11-12. GSU also maintains as-built schedules, maintenance work order packages, testing records, and condition reports. As-built schedules show the actual sequence and duration of the outage work as it takes place during the outage, and contain a detailed history of how the work was performed. *Id.* at 12.

Mr. Freehill testified that GSU is a member of the Boiling Water Reactors owners' group Outage Management Committee. This committee shares information on outages, schedules, reports, techniques for improvement, and other related topics. Based on his experience with this outage committee, he believes that GSU's documentation is much more detailed than the average boiling water reactor owner. If the Commission orders GSU to create and maintain additional documentation, Mr. Freehill argues that additional staff would be required, which would increase River Bend's operation and maintenance expenses. *Id.* at 15. Mr. Schlissel, however, did not recommend that GSU *create* any additional documents; rather, he only recommended that GSU *maintain* one copy of every document it creates.

The ALJ could not humanly review every document available to Mr. Schlissel in this case. As to whether requiring GSU to *maintain* one copy of every document it creates would drastically increase GSU's O&M expense, the ALJ cannot speculate. It seems foolhardy, however, for GSU not to maintain at least one copy of such documentation until it obtains a Commission order reconciling its fuel costs for that period. The responsibility to maintain sufficient documentation falls on the utility. To a certain extent, the management of that utility, after retaining those documents it is required by law to retain, faces a decision regarding additional document retention versus additional costs. Making the wrong decision could be very costly to the utility and its shareholders, which is where the burden appropriately lies. The ALJ makes no specific recommendation on this issue.

F. Utilization of Big Cajun II, Unit 3

Calvert witness Ms. Pitchford proposes disallowances for three months during the reconciliation period (November 1988, December 1989, and February 1990) based on her opinion that GSU should have generated more energy from Big Cajun II, Unit 3 during those months. Calvert Ex. 23B at 42-48. Her proposed redispatch of the Big Cajun unit is an alternative recommendation to her recommended disallowance pertaining to incremental coal discussed in Section V.B.1. of the Report.

***62** Ms. Pitchford's proposed disallowances for GSU's failure to use base coal to displace natural gas are as follows:

November 1988:	
Total system	$ (219,923)
Texas only	(79,032)
December 1989:	
Total system	$ (97,819)
Texas only	(37,966)
February 1990:	
Total system	$ (194,503)
Texas only	(73,816)
Total:	
Total system	$ (512,245)
Texas only	(190,814)

1. November 1988

In November 1988, GSU's capacity factor for Big Cajun II, Unit 3 was approximately 40 percent. If the capacity factor for Big Cajun II, Unit 3 had increased to 90 percent of equivalent availability, Ms. Pitchford calculated that $219,923 (total system) in fuel cost savings would have occurred.

Ms. Pitchford criticized the dispatch fuel cost and the heat rate data used by GSU to dispatch the Big Cajun unit in November 1988. She estimated that the dispatch fuel cost for the unit should have been $1.68/MMBtu based on invoiced coal and transportation costs, GSU's other estimated variable fuel costs, and a coal degradation factor of 2.5 percent. Calvert Ex. 23B at 42-43.

The fuel cost used by GSU to dispatch its share of the Big Cajun unit was $1.7646/MMBtu, which was based on the estimated cost supplied by Cajun Electric for 1988 coal purchases. GSU Ex. 76A at 32. The October 1988 funding statement provided to GSU by Cajun Electric forecasted a price of $1.4829/MMBtu. This forecasted price included a short-payment by Cajun Electric. GSU witness Mr. Champagne testified that GSU learned at the end of October 1988 that Cajun Electric had lost its litigation with Triton, its coal supplier, and was therefore required to make up the short-payments. The revised November 1988 funding statement showed a fuel price estimate for the month of $1.7235/MMBtu, unadjusted for coal degradation. *Id.* at 32.

GSU contends that Ms. Pitchford's estimated dispatch cost for Big Cajun II, Unit 3 was based on hindsight, using actual invoice data that was not available until after November 1988. Around the 20th of each month, GSU begins to determine its dispatch cost for the following month. Tr. 2745. Meanwhile, Cajun Electric receives the invoices from the coal supplier and transporters each month and then forwards them to GSU. The invoices for November 1988 coal supply and transportation were received by Cajun Electric in late October 1988. Mr. Champagne could not state exactly when GSU received these invoices from Cajun Electric, but he insists that it would have been after GSU made its plans for November 1988. Tr. 2744.

Ms. Pitchford also criticized GSU for not using incremental heat rate data to dispatch Big Cajun II, Unit 3. Incremental heat rate is the amount of fuel needed in Btus to generate one more KWH from a generating unit. Incremental heat rate data accounts for the variation in unit heat rate with load because fossil-fuel steam units normally have higher heat rates at low loads and lower heat rates at loads approaching design output. Use of incremental heat rate and fuel cost data permits the dispatcher to determine which generating unit can produce the next KWH for the lowest incremental cost. Calvert Ex. 23B at 44.

***63** GSU witness Mr. Champagne agrees with Ms. Pitchford's contention that normally a unit should be dispatched using incremental heat rate data. Nevertheless, he argues that it was not possible to use incremental heat rate data to dispatch jointly owned units where the joint owners do not always take energy in proportion to their capacity ownership.

Both Cajun Electric and GSU are entitled to independently dispatch or schedule their ownership share of Big Cajun II, Unit 3. Only if both utilities take the output of the unit in direct proportion to their ownership share at all times will both utilities receive equal benefits from incremental heat rates. If GSU increased its output from the Big Cajun unit based upon the incremental heat rate curve and Cajun Electric then reduced its output, the expected benefits from increasing GSU's output would not materialize. GSU Ex. 76A at 34-35; Tr. 2750. Mr. Champagne stated that GSU has discussed this issue with Cajun Electric, but a satisfactory solution has not been reached.

Because it does not control the output of the unit and cannot predict how Cajun Electric will use the unit, GSU schedules generation from Big Cajun II, Unit 3 based on average heat rate data. The heat rate data used for the November 1988 dispatch was the actual heat rate for September 1988 of 10,898 Btu/KWH, which Mr. Champagne claims was the most recent data available. This compared to the actual November 1988 heat rate of 9,872 Btu/KWH. GSU Ex. 76A at 36.

Even if GSU appropriately used the average monthly heat rate data from September 1988 for the November 1988 dispatch, Ms. Pitchford argues that the September 1988 data was faulty because of several unit startups and deratings during that month. Calvert Ex. 23B at 45. GSU argues, however, that the September 1988 heat rate was not unusual. Compared to the heat rates for June, July, August, and October of 1988, the September 1988 heat rate does not appear that disparate. Calvert Ex. 34 at 146707.

The ALJ recommends that Ms. Pitchford's proposed disallowance for November 1988 not be adopted. The ALJ is persuaded by the credible evidence indicating it is not possible to use incremental heat rate data to dispatch Big Cajun II, Unit 3 because GSU and Cajun Electric are entitled to independently dispatch or schedule their ownership share of the unit.

2. December 1989 and February 1990

Calvert witness Ms. Pitchford testified that GSU had not adequately explained its low dispatch of Big Cajun II, Unit 3 for December 1989 and February 1990. Therefore, she recommends a disallowance based on her calculation of excess fuel costs. Calvert Ex. 23B at 47.

GSU witness Mr. Champagne testified that Ms. Pitchford failed to account for operating conditions which affected GSU's utilization of its power plants. During December 1989, the first half of the month was mild but the third week was very cold. GSU had to burn oil and contract for off-system power subject to take requirements to offset curtailments of natural gas. GSU also burned long-term gas which caused it to exceed contract minimums. GSU Ex. 76A at 37-39. Mr. Champagne believes that GSU's use of long-term gas was reasonable because GSU did not have to disrupt power to its customers, even though its gas supply was disrupted. *Id.* at 39.

***64** According to Mr. Champagne, GSU implemented the same cold-weather precautions for February 1990, which included contracting for firm supplies of short-term gas to supplement its long-term gas. February 1990's weather, however, turned out to be mild in comparison to December 1989. In order to satisfy the minimum contract requirements under the long-term and short-term firm contracts, GSU had to decrease its discretionary power supply, including use of Big Cajun II, Unit 3. *Id.* at 39.

Based on the credible evidence and consistent with the recommendation in Section V.A.2. regarding the General Counsel's proposed disallowance for the Exxon contract, the ALJ recommends that Ms. Pitchford's proposed disallowances for December 1989 and February 1990 not be adopted. GSU has adequately and reasonably explained its dispatch of the Cajun unit for these two months.

G. Utilization of Sabine 5

Calvert witness Ms. Pitchford recommends a disallowance based on GSU's failure to use Sabine 5, a 480-MW gas-fired unit, as a peaking facility, contending that the facility was designed for peaking operation. Because GSU did not use Sabine 5 as a peaking facility, Ms. Pitchford testified that higher fuel costs due to higher system heat rates and/or failure to use less expensive fuels resulted. Calvert Ex. 23B at 6. She recommends the following amounts be disallowed:[FN19]

Total system	$ (706,011)
Texas only	(258,322)

Peaking service occurs when a unit may be taken off-line on a daily basis or over a weekend. During periods of low system load, the generating units in service must operate at lower loads, resulting in higher heat rates. If one of the units can be taken off-line instead of operated at a low load, then the load on the other units may be increased with a corresponding improvement in the system heat rate. Calvert Ex. 23B at 49-50. GSU's system dispatch operators would not start Sabine 5 for 72 hours after it was taken off-line, which effectively precluded Sabine 5 from being used as a peaking facility. *Id.* at 50.

There appears to be some disagreement as to whether Sabine 5 is currently capable of peaking service. Sabine 5 was designed for peaking service and has a design turbine heat rate consistent with peaking service; its turbine, however, was not purchased with peaking modifications because GSU expected to operate the unit in a load-following mode. Calvert Ex. 23B at 50-51; GSU Ex. 78 at 4. Ms. Pitchford testified that a unit need not be constructed specifically for peaking service in order to operate in that mode. Calvert Ex. 23B at 51. The question then becomes whether it is economical to nonetheless run the unit as a peaking facility, which requires a comparison of estimated fuel savings versus the cost to run the unit in a peaking mode.

In calculating her initial recommended disallowance, Ms. Pitchford assumed that Sabine 5 would be taken off-line for six hours each night when it was available during the months of April, May, and October. She then assumed that Sabine 3 would pick up the displaced generation. Ms. Pitchford computed the gas costs for operating Sabine 5 and Sabine 3 at minimum loads for six hours at night, as well as the costs associated with taking Sabine 5 off-line for six hours at night and increasing the load by a corresponding amount on Sabine 3. Calvert Ex. 23B at 53.

***65** According to GSU witness Mr. Irwin, however, Sabine 3 was already half-loaded at the times Ms. Pitchford assumed it would pick up the displaced Sabine 5 generation. During the months of April, May, and October, Sabine 3 had an average minimum load of 263 MW between the hours of 12 a.m. and 6 a.m. Because Sabine 3 has a net dependable capability of 420 MW, an additional unit would have to share in replacing generation from Sabine 5 if it were taken off-line, as recommended by Ms. Pitchford. Using Ms. Pitchford's methodology, Mr. Irwin used Sabine 1 to pick up some of the displaced generation. His calculations reduced her estimated fuel savings from $706,011 to $317,482. GSU Ex. 78 at 4; Tr. 1476-1480.

Ms. Pitchford submitted an errata in which she recognized that GSU would probably not be able to use Sabine 5 as a peaking facility if another unit - Sabine 4, in her assumption - was not also on-line. Based on this new assumption, her calculated disallowance would be lower for the months of April, May, and October, due to the unavailability of Sabine 4. Therefore, she recalculated her disallowance to use the months of June through September instead and estimated a total system disallowance of $818,000. Calvert Ex. 23A.

Mr. Irwin performed additional calculations based on Ms. Pitchford's errata testimony. Similar to the methodology used before, he calculated a total system disallowance of $539,000, not $818,000. He continued to insist, however, that any potential fuel savings from operating Sabine 5 in peaking mode would be outweighed by the additional costs associated with operating it as a peaking unit. GSU Ex. 78, Errata at 1.

Peaking service increases the stress and wear on the steam turbine components, resulting in increased maintenance and unit heat rate, and decreased reliability and life of the unit. If the heat rate increased by 50 Btu/KWH, or 0.5 percent, over normal wear due to peaking operation, Mr. Irwin calculated the increased total system fuel cost during the reconciliation period to be $587,152. GSU Ex. 78 at 5. Coupled with the estimated cost of $1,285,000 associated with an additional maintenance outage during the reconciliation period, Mr. Irwin calculated the total cost of running Sabine 5 in peaking mode to be $1,870,000. *Id.* This calculated cost estimate would, of course, negate any estimated fuel savings from operating the unit as a peaking facility.

The ALJ recommends that the Commission not adopt Ms. Pitchford's recommended disallowance for use of Sabine 5 during the reconciliation period. While there may be some fuel savings from having a unit operate as a peaking facility, it is also clear that peaking service will increase the operating and maintenance costs associated with taking the unit off- and on-line. Mr. Irwin effectively rebutted Ms. Pitchford's claim that operating Sabine 5 in the peaking mode would result in *net* fuel savings.

H. Other

1. Calvert Recommendation to Account for Purchase of Energy by Cajun Electric from GSU During Reconciliation Period

***66** Calvert witness Mr. Norwood recommends an adjustment to GSU's reconcilable fuel expense to account for Cajun Electric's purchase of energy from GSU during the reconciliation period in the amount of $82,989. Calvert Ex. 24 at 14. Mr. Norwood's recommendation is an alternative to Ms. Pitchford's recommended disallowance relating to use of incremental coal to displace natural gas, as discussed in Section V.B.1. of the Report. If the Commission adopts Ms. Pitchford's recommended disallowance, then Mr. Norwood's recommendation should not be adopted.

In April 1989, Cajun Electric and GSU entered into an agreement which permitted either party to purchase energy from the other party's ownership interest in Big Cajun II, Unit 3 at $3.50/MWH, with the purchasing party responsible for supplying the fuel. Calvert Ex. 24, Sch. DSN-8. During the reconciliation period, GSU sold 23,711 MWH to Cajun Electric under this agreement for $82,989, while it purchased 1,225 MWH from Cajun Electric for $4,288. Calvert Ex. 24 at 13.

GSU classified the $4,288 paid to Cajun Electric as a positive reconcilable fuel expense. It classified the $82,989 payment received from Cajun Electric, however, as non-reconcilable. Calvert recommended that the $82,989 payment also be treated as reconcilable, which would effectively reduce GSU's reconcilable fuel expense. The ALJ concurs with Calvert's recommendation. There is no credible evidentiary basis for treating GSU's payment to Cajun Electric as reconcilable but not its payment from Cajun Electric.

VI. Over/Under Calculation

A. Revenue Related Taxes and Fees

In its monthly billings, GSU collects revenues related to state and local gross receipts taxes and fees, the PUC assessment, and an uncollectible expense, all of which are a function of the amount of KWH sold. The issue is whether such revenue-related taxes and fees associated with an alleged overcollected fuel expense should be disallowed in addition to any overrecovery.

Beaumont witness Mr. Pous contends that GSU should not retain any of these revenue-related taxes or fees associated with the alleged overcollected fuel expense for equity reasons; otherwise, the company would receive a windfall. To the extent that GSU overrecovered the underlying fuel expense, he reasons that the related taxes and fees were also overcollected. Beaumont Ex. 14 at 65-67. Using Beaumont's recommendations, the total amount of overrecovery for revenue-related taxes and fees is $763,863. Beaumont Ex. 17, Sch. JHB-2. OPC supports Beaumont's position. OPC Brief at 72.

GSU and the General Counsel argue that Mr. Pous' recommendation constitutes an improper, retroactive adjustment to base rates. Although the revenue-related taxes and fees cited by Mr. Pous are related to the reconcilable fuel revenue, they are also base rate items set by the Commission in a rate case. The Commission rejected a similar recommendation made by Mr. Pous in Docket No. 9300. Docket No. 9300, 17 P.U.C. BULL. at 2619-2620, 2683 (Finding of Fact No. 392), 2729, 2825. [13] While Mr. Pous' argument is initially appealing, the ALJ concludes it must be rejected. The items that Mr. Pous desires to adjust are base rate items, even though they are related to the fuel balance at issue. The Commission recently considered the issue of whether to adjust revenue-related taxes and fees in Docket No. 9300 and declined to do so. Additionally, if Mr. Pous' recommendation is adopted, GSU would be required to refund monies which it no longer possesses. The revenues generated by the taxes and fees are forwarded by GSU to the assessing governmental entities. GSU Ex. 97 at 55-56. OPC's argument that GSU should not be allowed to charge an improper expense to its ratepayers simply because it is *required to pay it* is nonsensical. OPC Brief at 73.

B. Incentive Rates

***67** GSU witness Mr. Bobby J. Willis testified that GSU changed the accounting method by which it allocated reconcilable fuel expense to the Texas jurisdiction. Starting in June 1991, the fuel expense related to certain GSU incentive rates was subtracted from GSU's total reconcilable fuel and purchased power expense before these expenses were allocated to the Texas jurisdiction and an over/underrecovery calculation was made. GSU Ex. 29 at 8-9. In addition, GSU removed the Texas incremental KWH sales from total Texas retail sales, and removed the total incremental KWH sales from the total system KWH sales. GSU Ex. 98 at 4-5. GSU believes that exclusion of the incremental expense and KWH sales from the reconcilable fuel balance avoids inequitable results to ratepayers and shareholders. *Id*. GSU further contends that this accounting change was prompted by the Commission's concern that ratepayers would be harmed if the incentive rate fuel expense was not subtracted from reconcilable fuel prior to jurisdictional allocation. Calvert Ex. 24, Sch. DSN-10.

Calvert argues that Texas ratepayers are harmed by GSU's subtraction of the incentive rate fuel expense from total reconcilable fuel costs. The alleged harm occurs because incentive rates are based on incremental costs, which happened to be lower than average costs during the reconciliation period. Including the incentive rate fuel expense in reconcilable fuel decreases the reconcilable fuel balance by $517,095. Calvert Ex. 24 at 16. OPC supports Calvert's position. OPC Reply Brief at 80.

The General Counsel and GSU contend that it is proper to exclude the incentive rate fuel expense from total reconcilable fuel costs. Customers paying incentive rates are not charged pursuant to the fixed fuel factor; rather, they are charged the incremental cost of fuel, whatever that cost happens to be when the customer uses electricity. To include the incremental expense and associated sales would result in both non-fixed fuel factor customers and fixed fuel factor customers being allocated an expense based on a combined incremental and system average cost. GSU Ex. 98 at 6. GSU witness Mr. Henkel argues that this combined approach defeats the proper matching of fuel expense and fuel revenue for customers billed pursuant to the fixed fuel factor.

Whether ratepayers are harmed by the exclusion or inclusion of incentive rate fuel expense depends upon whether incremental cost is less than or greater than system average cost. Incremental cost was less than system average cost during the reconciliation period in this instance. Consequently, its inclusion in the reconcilable fuel balance would naturally decrease the amount of reconcilable fuel expense. If incremental expense had been higher than system average cost, its inclusion would have increased the amount of reconcilable fuel expense. [14] Whether the incentive rate fuel expense should be included in or excluded from the reconcilable fuel balance is not a matter appropriately resolved simply upon whether the reconcilable fuel balance goes up or down. Otherwise, the Commission's decision would flip-flop from case to case, depending on whether incremental cost was less than or greater than system average cost. Therefore, the ALJ finds that it is reasonable to exclude incentive rate fuel expense, as recommended by GSU and the General Counsel.

C. Interest Calculation

***68** Two interest rates are applicable to the refund or surcharge calculation for the reconciliation period in this case: (1) 11.48 percent, approved in Docket No. 7195, which is applicable to all interest calculations from September 1988 through February 1991; and (2) 11.94 percent, approved in Docket No. 8702, which is applicable to all interest calculations from March 1991 through September 1991. Beaumont Ex. 17 at 4.

There is no contested issue with respect to the proper interest rate to be applied; rather, the dispute is whether a simple or compound interest calculation should be employed. Because the Commission's rules do not prescribe whether simple or compound interest is to be used in calculating the interest on a fuel over- or underrecovery, Commission precedent governs. Such Commission precedent has routinely utilized simple interest calculations for deferred fuel balances.

P.U.C. SUBST. R. 23.23 governs the refund methodology used in fuel reconciliation proceedings. It does not state whether a simple or compound interest methodology should be used to calculate a refund. The rule does require, however, that the interest be based on the utility's composite cost of capital as established by the Commission and in effect during the reconciliation period, calculated on the cumulative monthly over- or underrecovery balance. P.U.C. SUBST. R. 23.23(b)(2)(G)(i) and 23.23(b)(2)(I). Other substantive rules, dealing with customer deposits and over- and underbillings, require interest to be compounded annually. P.U.C. SUBST. R. 23.43(c)(3); 23.45(g). There is no provision in the substantive rules which requires the monthly compounding of interest. No party cited a case in which compound interest, monthly or annually, was applied to a deferred fuel balance.

GSU used the simple interest methodology to calculate the interest on its alleged underrecovery balance. GSU Ex. 79 at 1. Beaumont witness Mr. Baker recommends that interest be compounded monthly in fuel reconciliation proceedings. Beaumont Ex. 17 at 10; Tr. 1849. Using Beaumont's recommendations, the effect of utilizing compound versus simple interest would increase Beaumont's recommended refund by $1,518,668 at the end of the reconciliation period. Beaumont Ex. 17 at 10, Sch. JHB-2.

Mr. Baker proposes a monthly compounding of interest because he believes such to be the only methodology which took into full account the time value of money. Tr. 1856. He agrees that his recommendation should equally apply to calculating interest on a surcharge. If GSU had under-recovered its fuel expenses during the reconciliation period, his recommendation to compound interest monthly would increase the amount of the surcharge to the ratepayers. Tr. 1850-1851. Mr. Baker admits that the Commission precedent supported the use of a simple interest methodology. Tr. 1846. He was also not aware of any Commission precedent contrary to the simple interest methodology calculation for fuel under- or overrecoveries. Tr. 1847.

***69** General Counsel witness Ms. Schultz recommends that the interest calculation be based on the simple interest methodology. General Counsel Ex. 10 at 12. She explained that the Commission's policy regarding the calculation of interest in fuel reconciliation cases, established through precedent since 1987, is based on four assumptions:

1. The current month's deferred fuel over- or underrecovery balance arises as of the first day of the current month; 2. Consistent with No. 1 above, refunds of overrecoveries are assumed to be made on the first day of the month in which the refund is made; 3. Interest is calculated using the actual number of days in the year and the actual number of days in the applicable month; and 4. Interest is calculated through the month preceding the month of the refund.

Ms. Schultz verified that GSU calculates interest using the above assumptions, but noted that neither she nor GSU calculated interest through the month preceding the month of refund or surcharge because the date of the final order in this case is not known. Id. at 12-13. If the Commission orders a refund or a surcharge, interest must be calculated through the month preceding the month of the refund or surcharge ordered.

Ms. Schultz conceded that she would consider recommending compound interest, despite Commission precedent to the contrary, but states she would need to consider other factors before making such a recommendation. She cited the interest rate to be applied and the length of the refund or surcharge period as pertinent to her consideration. Tr. 2236.

GSU witness Mr. Willis testified on rebuttal that GSU has accrued simple interest on the deferred fuel balance during the reconciliation period in compliance with Commission precedent and prior GSU fuel proceedings. GSU Ex. 79 at 1-2. He believes that it would be unfair to switch to a compound interest calculation at this point. Mr. Willis notes that the provisions in the substantive rules which require annual compounding of interest involve lower interest rates tied to short-term investments: 6.0 percent for customer deposits and 6.25 percent for over- and underbillings, which are much less than 11.48 percent and 11.94 percent, GSU's weighted cost of capital during the fuel reconciliation period. *Id.* at 3. He does not believe it is appropriate to compound an already high interest rate.

Because the Commission recently declined to adopt a compound interest methodology in Docket No. 9300[FN20] and because the Commission precedent is *consistent* with regard to use of simple interest for deferred fuel balances, the ALJ recommends using the simple interest calculation as recommended by GSU and the General Counsel. A change in the policy for calculating interest on deferred fuel balances which affects all utilities subject to fuel reconciliations should be debated in a rulemaking proceeding, and not applied on a case-by-case basis to some utilities and not others.

D. Refund/Surcharge Methodology

***70** The parties raised two issues with respect to the refund or surcharge methodology: (1) the time period for the refund or surcharge; and (2) whether historical or forecasted consumption of customers or customer classes will be used to allocate any refund or surcharge to customer classes and transmission-level customers.

1. The Appropriate Time Period for the Refund or Surcharge

P.U.C. SUBST. R. 23.23(b)(2)(G)(v) provides:

All refunds shall be made through a one-time bill credit unless it can be shown that this method would provide an incentive for customers to benefit from excessive usage of electricity. However, refunds may be made by check to municipally-owned utility systems if so requested. Retail customers who receive service at transmission voltage levels, all wholesale customers, and any groups of seasonal agricultural customers as identified by the utility shall be given a lump sum credit. All other customers shall be given a credit based on a refund factor which will be applied to their kilowatt-hour usage over a one-month period. This refund factor will be determined by dividing the amount of refund allocated to each rate class, by forecasted kilowatt-hour usage for the class during the month in which the refund will be made.

The substantive rule clearly requires a one-time bill credit for implementing refunds unless it can be shown that the short time frame would be an incentive to use electricity excessively. The rule is silent, however, with regard to the methodology for implementing surcharges.

GSU recommends applying its proposed surcharge over a 12-month period. GSU Ex. 40 at 6. Mr. Henkel testified that use of a 12-month period is consistent with GSU's last two rate cases. GSU Ex. 98 at 2. TIEC and OPC, however, recommend recovery of their proposed refunds through a one-time credit, as specified by the substantive rule. In the event the Commission finds an underrecovery necessitating a surcharge, TIEC recommends that a surcharge be accomplished over a 24-month period. TIEC Ex. 10 at 31-32.

The ALJ finds TIEC's argument in brief to be very persuasive on this issue. TIEC Brief at 24-26. Counsel for TIEC correctly notes that GSU's reliance on Docket Nos. 7195 and 8702 is misplaced. In those dockets, the Commission made specific findings regarding GSU's financial condition to support approval of a longer time period for accomplishing refunds than allowed by the substantive rule. *Application of Gulf States Utilities Company for Authority to Change Rates*, Docket No. 7195, Finding of Fact No. 240, 14 P.U.C. BULL. 1943, 2417 (May 16, 1988); Docket No. 8702, Finding of Fact No. 56, 17 P.U.C. BULL. 703, 1022 (May 2, 1991).

The ALJ finds that GSU has failed to show good cause to deviate from the requirements of P.U.C. SUBST. R. 23.23(b)(2)(G)(v), which requires a one-time bill credit for refunds. GSU did not present any evidence on this issue, and it cannot now look for solace in findings made in its last two rate cases. Because the ALJ's recommendations in this docket result in a refund and not a surcharge, she does not need to resolve the issue of an appropriate time period for processing a surcharge in a fuel reconciliation proceeding.

***71** *2. The Appropriate Allocation of the Refund - Historical or Forecasted and KWH Consumption or Relative Revenue Contribution.*

GSU recommends that its proposed surcharge be based on *forecasted KWH consumption* over a 12-month period. Mr. Henkel reasons that since the substantive rule did not address the methodology for surcharges, the Commission could adopt a prospective rather than historical basis for computing the proper amount of surcharge. GSU Ex. 98 at 2. The General Counsel also recommends a surcharge in this proceeding. Mr. Rosenblum testified that the surcharge factor should be determined by dividing the total underrecovery balance by *projected KWH sales at the meter*, excluding sales not subject to the fixed fuel factor. The surcharge factor would then be adjusted for losses. General Counsel Ex. 12

at 9-10.

In contrast, OPC and TIEC found an overrecovery necessitating refunds in this case. OPC recommends that its proposed refund be based on the relative *revenue* contribution of each rate class in the *historical* period, OPC witness Mr. Needler believes that the customers should receive refunds in relation to the money each paid towards the overrecovery of fuel costs. OPC Ex. 45 at 3. Similarly, TIEC witness Mr. Pollock recommends that refunds for the transmission level, wholesale, and seasonal agricultural customers be based on each customer's *historical KWH consumption*. TIEC Ex. 10 at 31.

The ALJ recommends that the refunds recommended in this case be accomplished in accordance with P.U.C. SUBST. R. 23.23(b)(2)(G)(i) through (v). Subsection (G)(iii) provides:

Interclass allocations of refunds including associated interest shall be developed on a month-by-month basis and shall be based on the historical kilowatt-hour usage of each rate class for each month during the period in which the cumulative overrecovery occurred, adjusted for line losses using the same commission approved loss factors that were used in the utility's applicable fixed or interim fuel factor.

Subsection (G)(iv) provides:

Intraclass allocations of refunds shall depend on the voltage level at which the customer receives service from the utility. Retail customers who receive service at transmission voltage levels, all wholesale customers, and any groups of seasonal agricultural customers as identified by the utility shall be given refunds based on their individual actual historical usage recorded during each month of the period in which the cumulative overrecovery occurred, adjusted for line losses if necessary. All other customers shall be given refunds based on the historical kilowatt-hour usage of their rate class.

Because the ALJ's recommendations result in a refund to GSU's customers, the ALJ does not need to reach the issue of the appropriate methodology used to implement surcharges.

VII. Fuel Factor Determination

A. Determination of the Proper Fuel Year and Methodology

GSU and the General Counsel used different methods and proposed fuel years to calculate their respective fixed fuel factors in this case. GSU's proposed fuel year is July 1, 1992, through June 30, **1993**, while the General Counsel proposed a calendar year **1993** fuel year. GSU Ex. 39 at 2; General Counsel Ex. 7 at 16. GSU used PROMOD, a production cost simulation model, for its fuel factor calculations, while the General Counsel used a spreadsheet analysis. *Id.* at 16. Calvert, the only other party to state a position on the fuel year issue, supports the adoption of the General Counsel's proposed fuel year and methodology.

***72** GSU does not believe that the differences in the parties' methodologies and fuel years were ultimately significant, given that GSU and the General Counsel proposed fuel factors of 2.0211 and 1.9894 cents per KWH, respectively. GSU Ex. 40 at 5; Tr. 2398. Therefore, GSU did not rebut the **1993** fuel year proposed by the General Counsel. GSU's position was based on the similarity in results between its calculated fuel factor and the General Counsel's fuel factor. Despite this position, GSU does not endorse the specific assumptions made by the General Counsel's witnesses in calculating their proposed **1993** fuel year fixed fuel factor, and urges that its fuel year be adopted. GSU Brief at 183.

GSU makes four arguments in brief as to why its fuel year and methodology should be adopted in calculating the fixed fuel factor in this case: (1) the disposition of a case well into the proposed fuel year is neither uncommon nor a cause for concern; (2) GSU's fuel year includes a partial nuclear refueling outage which resulted in the non-use of the River Bend unit for approximately six weeks, thereby decreasing potential generation from the plant; (3) PROMOD is more accurate than a spreadsheet analysis; and (4) use of PROMOD relieves the administrative burden on the parties and the Commission because GSU has the resources to calculate the fuel factor expeditiously and accurately. GSU Brief at 183-185.

GSU may correctly observe that the Commission has disposed of certain fuel dockets after the proposed fuel year adopted in those proceedings has begun. In this case, however, GSU's proposed fuel year will be nearly completed by the time all motions for rehearing are exhausted. The General Counsel and Calvert argue that the intent of the Fuel Rule requires that the fuel factor be developed using information relating to the period in which the fuel factor is expected to be in effect - the fuel year. P.U.C. SUBST. R. 23.23(b)(2)(C) provides:

The utility shall recover its known and reasonably predictable fuel costs through a fixed fuel factor. The utility's fixed fuel factor shall be established during a general rate case, fuel reconciliation proceeding or interim fuel proceeding as designated in subparagraphs (D) and (E) of this paragraph, and shall be determined by dividing the utility's known or reasonably predictable fuel cost, as defined in subparagraph (B) of this paragraph, by the corresponding kilowatt-hour sales *during the period in which the factor will be in effect*. [Emphasis added.]

[15] The ALJ concurs in the General Counsel's and Calvert's position that the language of the substantive rule supports the conclusion that the fuel factor be based on information projected for the fuel year. This interpretation alone, however, does not automatically support adoption of a proposed fuel year if that fuel year is otherwise so deficient or inaccurate as to undermine the benefits of its adoption. While the ALJ recommends adjustments to components of the General Counsel's proposed fuel year, she does not find it so deficient or inaccurate as to compel rejection.

***73** GSU alleges that the General Counsel's fuel year overstates generation from River Bend, contending that its six-week refueling outage more accurately projects River Bend generation. Calvert correctly notes, however, that GSU did not cross-examine General Counsel witness Mr. Chester Oberg regarding his use of a two-week maintenance outage in the projected fuel year to calculate projected generation from River Bend. General Counsel Ex. 5 at 11-12; Tr. 2095-2100. In making his projection of River Bend generation for the **1993** calendar year, Mr. Oberg assumed a forced outage rate of 8 percent; included the two-week mid-cycle maintenance outage referenced above; and assumed an average derating of 35,348 MWH for each month of operation. Based on these factors, Mr. Oberg calculated an average capacity factor of 83 percent for River Bend, compared to GSU's projected 80 percent capacity factor. *Id.* at 12. While Mr. Oberg's capacity factor is higher than GSU's, the General Counsel actually predicted 13.0 percent lower generation from River Bend during the first six months of **1993** than GSU. General Counsel Ex. 7, Sch. JEN-4 at 2. GSU's criticism in brief of Mr. Oberg's use of a two-week maintenance outage is not persuasive given the above information.

Finally, GSU argues that its PROMOD model can more accurately and expeditiously calculate the fuel factor than the General Counsel using Mr. Neeley's spreadsheet analysis. Calvert and the General Counsel agree that PROMOD is generally more accurate and sophisticated than a spreadsheet analysis. Calvert Reply at 87; Tr. 2172. Calvert could not agree, however, with certain assumptions used by GSU to model PROMOD. Apparently, those assumptions are not in evidence. Calvert Reply at 88.

The ALJ recommends that the General Counsel's proposed calendar year **1993** fuel year, as adjusted by the ALJ, and Mr. Neeley's spreadsheet methodology be adopted for the purpose of calculating the fuel factor in this proceeding. While PROMOD may indeed be more accurate than Mr. Neeley's spreadsheet analysis, that characteristic alone does not persuade the ALJ to adopt GSU's methodology. The contested assumptions underlying the PROMOD modeling which are not in evidence weigh against the use of PROMOD, making it impossible for the ALJ to recommend its adoption. Even if that information were in the record, however, the fact remains that GSU failed to present a rebuttal case addressing the General Counsel's **1993** proposed fuel year. The General Counsel's fuel year is based on information projected for the time in which the factor will be in effect. As modified by the ALJ, it is more appropriate than GSU's proposed fuel year.

Other than the issues discussed above and those discussed in Sections VII.B. through VII.J. relating to the fuel factor calculation, the parties did not specifically brief other matters related to the fuel year. Except where otherwise noted by the ALJ, the ALJ recommends adoption of the components of the General Counsel's proposed fuel year.

***74** *B. Payments to Sabine Gas Transmission Company*

1. General Background

In August 1991, GSU and Sabine Gas Transmission Company (SGT) entered into the 1991 Amended and Restated Gas Transportation Agreement (the Transportation Agreement), which requires SGT to provide transportation and swing service to GSU in return for a transportation fee paid by GSU. TIEC Ex. 12. GSU argues that the costs associated with the Transportation Agreement were fuel-related costs which were properly included in the fixed fuel factor calculation. GSU's payments to SGT only affect the fixed fuel factor calculation in this proceeding because the Sabine Spindletop project was not in operation during the reconciliation period.

TIEC, OPC and North Star Steel contend that the payments to SGT are not reconcilable fuel costs includible in the fixed fuel factor calculation, contending rather that the arrangement between GSU and SGT resulted in GSU's acquisition of a facility which should be included in rate base. On its face, GSU's rather complicated arrangement with SGT is either a smart management initiative aimed to reduce costs, or a clever ruse to recover non-reconcilable costs in the fuel factor during a base rate moratorium.

SGT began construction of an underground gas storage facility near GSU's Sabine Station to meet its obligations under the Transportation Agreement. The storage facilities will be developed in three phases. Phase I, already in operation, consists of the development of a storage cavern having a capacity of not less than 1 billion cubic feet. A second storage cavern will be constructed in Phase II having a storage capacity of 5 billion cubic feet. Following the completion of Phase II, SGT will enlarge the initial storage cavern to a capacity of 5 billion cubic feet. This last enlargement constitutes Phase III of the storage facility. TIEC Ex. 9 at 3-4. When completed, the project will consist of two underground caverns with a combined capacity of 10 billion cubic feet. GSU Ex. 22 at 9.

The Sabine Spindletop Pipeline will be constructed from the Texas Sabine Pipeline to the Spindletop salt dome and salt caverns.[FN21] The total storage quantity consists of working gas and cushion gas. Cushion gas makes up approximately one-third of the cavern's size and will remain in the storage project. GSU will supply the cushion gas free of cost to SGT provided that, subject to availability of financing, SGT will purchase it from GSU at GSU's cost. The cost of the cushion gas will become a part of the installation costs. Working gas is the quantity in excess of the cushion gas and is generally moved in and out of storage under normal operating conditions. TIEC Ex. 9 at 3.

The Transportation Agreement provides for GSU's delivery of gas to the Texas Sabine Pipeline System and re-delivery to GSU on a delayed basis. GSU pays SGT a monthly transportation fee per MMBtu of gas delivered to SGT's pipeline system plus a charge for electricity to operate the storage facility. SGT credits a portion of the transportation fee received from GSU to the 'Non-Credit Payment;' the remainder of the fee is credited to the 'Credit Payment.'

***75** The Non-Credit Payment is an amount per MMBtu subject to adjustment, while the Credit Payment is the remainder of the transportation fee in excess of the Non-Credit Payment. TIEC Ex. 12 at 19-20. The Credit Payment is applied by SGT against the 'Payoff Amount,' which consists of SGT's installation costs for the Spindletop facility including interest. The Payoff Amount is adjusted each month by the Credit Payment and accrued interest. When the Payoff Amount equals zero, the Credit Payment portion of the transportation fee is eliminated. *Id.* at 23.

GSU is also required under the Transportation Agreement to deliver a minimum quantity of gas to SGT or pay an Amortization Fee based on the minimum quantity not delivered. This minimum quantity payment is $9,000,000. When the Payoff Amount reaches zero, the minimum quantity obligation is also eliminated. *Id.* at 24-25.

Under the second agreement with SGT, the 1991 Amended and Restated Optional Purchase and Amortization Agreement (the Optional Purchase and Amortization Agreement), GSU has the option to purchase the facilities from SGT for a sum equal to the Payoff Amount, provided that the purchase price is not less than one dollar. TIEC Ex. 13 at 14-15. The current market value of the facilities is approximately $40,000,000. Tr. 2854.

GSU expects the gas storage capability of the Sabine project to provide the maximum/minimum swing requirements presently supplied by GSU's existing suppliers.FN22 If GSU must rely upon its other suppliers for swing service, instead of SGT under the transportation agreement, GSU argues that the cost of swing service from those other suppliers would be recovered through the fuel factor. By accepting a more levelized flow from its other suppliers, GSU believes it can negotiate lower prices that do not reflect a swing delivery component. Consequently, Mr. Harrington expects the additional storage facilities will improve GSU's leverage in negotiating and acquiring lower cost natural gas and reduce its overall dependence on long-term gas contracts. GSU Ex. 22 at 10-11. GSU also anticipates being able to swing Sabine Station and Lewis Creek with these new facilities.

GSU claims that significant benefits will result from the Sabine project, including system fuel savings, fuel mix savings, seasonal savings, and daily swing savings. GSU Ex. 23B. Under GSU's worst case scenario, after adjusting for the minimum fuel burn at Sabine Station, expenses will average approximately $11,258,000 per year over the first seven years, but will be offset by an average annual projected savings over those seven years of approximately $11,568,000. At the end of the seventh year, GSU projects a cumulative net present value savings of $403,000 under the worst case scenario. Under GSU's expected case scenario, it projects a cumulative net present value savings of $48,879,000 at the end of the seventh year. GSU Ex. 77A at 8-9.

Mr. Harrington also asserts that any savings which resulted from the Spindletop project accrue to ratepayers, rather than GSU. In other words, GSU shareholders would not profit from this arrangement. GSU Ex. 77A at 7. If the payments to SGT are recovered through the fixed fuel factor, GSU has agreed to credit revenues received from the existing facility to off-set the reconcilable fuel expense. GSU Brief at 206; GSU Reply Brief at 98; Tr. 2870-2872. If GSU exercises its option and then sells the Spindletop property or engages in a sale/leaseback, it argues that the Commission would review any such sale or sale/leaseback under PURA § 63 to determine the appropriate disposition of the gain on the sale between the ratepayers and shareholders. GSU Reply at 99.

***76** Although OPC took a minor stab at criticizing the expected benefits of the project, there is no credible, serious challenge to GSU's claims of expected benefits relating to reduced gas prices or increased flexibility. General Counsel Ex. 14 at 13-15; OPC Ex. 45 at 9. Whether the Spindletop project ultimately leads to savings or produces expected benefits, however, is not dispositive of whether the payments to SGT are properly includible in the fixed fuel factor. That determination turns on the application and interpretation of the Commission's Fuel Rule.

2. Whether the Payments to Sabine Gas Transmission Company are Properly Includible in the Fixed Fuel Factor

GSU argues that the payments to SGT are reconcilable, fuel-related costs properly included in the fuel factor under P.U.C. SUBST. R. 23.23(b)(2)(B)(i) and (ii) and the Commission's decisions in Docket Nos. 8425 and 9300. OPC, TIEC, and North Star Steel disagree, contending that the payments are not reconcilable, fuel-related costs. They aver that the arrangement with SGT results in GSU's acquisition of a capital or fixed asset which should be included in rate base.

a. P.U.C. SUBST. R. 23.23(b)(2)(B)(i) and (ii) and Commission Precedent

P.U.C. SUBST. R. 23.23(b)(2)(B)(i) specifies the factors and costs the Commission must consider in identifying a utility's known or reasonably predictable fuel costs:

In determining known or reasonably predictable fuel costs, the commission shall consider all conditions or events which will impact the utility's fuel-related cost of supplying electricity to its ratapayers during the period that the rates will be in effect. These conditions or events include generation mix and efficiency, the cost of fuel used to produce the utility's generation, purchased power costs, wheeling costs, hydro generation and other costs or revenues associated with generated or purchased power as approved by the commission.

P.U.C. SUBST. R. 23.23(b)(2)(B)(ii) specifies six types of costs which the Commission cannot include within the category of known or reasonably predictable fuel costs:

Purchased power capacity costs, fuel handling costs, costs associated with the disposal of fuel combustion residuals, railcar maintenance costs, railcar taxes, and coal brokerage fees will not be included as known or reasonably predictable fuel costs to be recovered through the fixed fuel factor as defined in subparagraph (C) of this paragraph, unless the utility demonstrates that such treatment is justified by special circumstances.

TIEC and OPC argue that the six exclusions specified in P.U.C. SUBST. R. 23.23(b)(2)(B)(ii) should be interpreted only as examples in determining whether a cost should be excluded from the fixed fuel factor calculation. TIEC Ex. 10 at 25; OPC Ex. 45B at 6. The Commission recently held, however, that all known or reasonably predictable fuel costs, *whether fixed or variable, and not specifically excepted by the Fuel Rule*, should be included in the fixed fuel factor. *Application of Texas Utilities Electric Co. for Authority to Change Rates*, Docket No. 9300, Finding of Fact No. 223, 17 P.U.C. BULL. 2057, 2777 (September 27, 1991). This holding also appears to reject the arguments made by certain parties in prefiled direct testimony that it is appropriate to use a standard based on variability or volatility to determine whether a cost is reconcilable.[FN23]

***77** The parties also argued extensively about the import of Docket No. 8425, in which the Commission included costs for HL&P's leased North Dayton gas storage facility in HL&P's known and reasonably predictable fuel costs. HL&P's North Dayton costs included a facility use fee, an O&M fee, insurance and taxes, and an electricity cost connected to the injection of gas into the facility. The ALJ in Docket No. 8425 relied on the following definition of fuel cost to recommend that the North Dayton costs be excluded from reconcilable fuel costs: 'fuel cost' includes only the cost of commodities used to generate electricity and other costs that cannot be separated easily from the cost of the commodities. Docket No. 8425, 16 P.U.C. BULL at 2317-2318.

The Commission overruled the ALJ's recommendation and granted HL&P's request for reconcilable treatment. Of particular interest are Findings of Fact Nos. 94, 94A, and 94B:

94. As shown in the Phase I rebuttal testimony of Company witness Mr. Brackeen, the storage capability provided by the North Dayton storage facility is a central feature of the Company's gas acquisition strategy. The costs of this facility are incurred in an effort to reduce overall costs since it allows the Company to take advantage of spot market purchase opportunities. 94A. As shown in the Phase I rebuttal testimony of Company witness Mr. Brackeen, if the Company had not separately paid for gas storage then any gas storage services purchased by the Company would have been provided by gas suppliers and charged to the Company through increased gas prices. The increase in gas prices would have been recovered through the fuel factor. 94B. In determining the Company's known or reasonably predictable fuel costs, the Commission considered all conditions or events that affected the Company's fuel related cost of supplying electricity to consumers. Known or reasonably predictable fuel costs may include those costs that show that the Company has planned and operated its facility and fuel-procurement programs prudently, with the objective of providing reliable power at the lowest reasonable total cost. Based upon the two previous findings of fact, the Company's North Dayton costs incurred during the reconciliation period should be reconciled.

16 P.U.C. BULL. at 2720. Although TIEC and OPC argue that Docket No. 8425 is distinguishable, claiming GSU is purchasing rather than leasing the Sabine Spindletop facilities, it appears, rightly or wrongly, that GSU's payments to SGT fall within the parameters in Docket Nos. 8425 and 9300 for reconcilable fuel costs. GSU has historically included transportation fees as reconcilable fuel costs regardless of whether the transportation fee was separately identified, and the Commission historically has not disagreed with GSU's treatment in prior dockets. GSU Ex. 79 at 4-5.

b. Whether Payments Acquire Capital or Fixed Asset Requiring Payments to SGT to be Included in

Rate Base and Not in Fixed Fuel Factor

***78** TIEC, OPC, and North Star Steel contend that GSU is, in actuality, purchasing the Sabine Spindletop facilities, which requires GSU to seek rate base treatment of its payments to SGT. GSU does not have legal title to the facility, nor does it have the risk of liability from owning or operating the facility. Tr. 2913; 2924-2925. The intervenors, however, point to GSU's control over the project, its option to purchase the facilities, and GSU's accounting method for the project as a capital lease. They allege that GSU is paying the capital cost for the project and that such costs would be included in rate base had GSU financed and constructed the project itself. Because GSU does not have legal title to the project or the land, the question becomes whether certain indicia of ownership or control can convert a lack of legal title and actual investment into a requirement of rate base treatment.

i. GSU's Control Over the Project

The testimony is undisputed that GSU's arrangement with SGT is unusual - no witness could cite a comparable arrangement. GSU agrees that the option and control provisions distinguish its arrangement with SGT from other ordinary transportation agreements. It argues, however, that these provisions benefit GSU and its ratepayers.

Although GSU is not the legal owner of the facilities or the land upon which the facilities are located, it has significant authority to direct the construction, design, and operation of the facilities by SGT. Among other rights, GSU has the right to approve the budget, engineering designs, bid specifications, selection of the contractor, equipment specifications, and the terms of storage agreements between SGT and third parties. Tr. 2802; 2834-2835. As for the last contractual right, any revenue derived from third party storage is credited to GSU, although GSU maintains that any such revenue will be credited to the ratepayers. Tr. 2909-2910. Further, GSU is the manager of the construction project, operates and maintains the equipment on SGT's pipeline, and provides contract administrative services to SGT. Tr. 2612-2613; 2832.

GSU does not dispute that it has significant authority over the facilities, and in fact, points to that authority as the basis for its ability to procure cost savings for the ratepayers. GSU witness Mr. Harrington testified that SGT is precluded from expanding the facilities without GSU approval, so that GSU can prevent SGT from profiting from the initial capital intensive nature of constructing the storage facility by adding additional storage after GSU's storage needs were met. Tr. 2904-2905. With regard to the purpose underlying control over construction and specification of equipment, Mr. Harrington responded that GSU wanted the facility constructed in the proper manner in the event GSU exercised its option on the facility. Tr. 2906. Finally, GSU wants to maintain control over third-party use of the storage facility to prevent SGT from retaining any revenue received from third parties, given that GSU plans to instead use such revenue to reduce the Payoff Amount and, ultimately, the transportation fee. Tr. 2909. [16] GSU has plausibly rebutted the intervenors' contention that the control provisions aim to effect the acquisition of the facilities by GSU. Regardless of GSU's contractual rights and authority, its control over the design, construction, and operation of the Sabine Spindletop facilities does not require GSU to seek rate base treatment for its payments to SGT.

***79** *ii. GSU is Paying SGT's Capital Cost for Project*

TIEC and OPC argue that GSU is paying the capital costs of the Sabine Spindletop construction through the Credit Payment portion of the transportation fee and the minimum annual payment, which consequently require the inclusion of GSU's payments to SGT in rate base, not the fuel factor. OPC Ex. 45B at 5; TIEC Ex. 9 at 8. According to OPC witness Mr. Needler and Mr. Mallincrodkt, the Credit Payment portion of the transportation fee is a non-gas related cost which GSU is using to finance the construction of the facility because 100 percent of the Credit Payment, which is paid on a per MMBtu basis, goes to reducing the Payoff Amount.

GSU witness Mr. Harrington agrees that the Credit Payment is a non-gas cost, but argues that it is not even a GSU cost - the Credit Payment is an SGT obligation. GSU Ex. 77A at 20. The terms Credit

Payment and Non-Credit Payment are contractual terms used to define SGT's use of the proceeds received from GSU. According to Mr. Harrington, GSU pays SGT a fee for transportation and swing service, and SGT portions out the proceeds between a Credit Payment and a Non-Credit Payment. GSU Ex. 77A at 3. Although a portion of the fee paid by GSU will be used by SGT to pay off its construction investment in the facility, Mr. Harrington claims that this application towards capital costs is not novel and does not transform the fee paid by GSU into a non-reconcilable fuel cost. According to Mr. Harrington, all gas companies use a portion of the fee they receive to defray capital costs. *Id.* at 4; Tr. 1867-1868; 1932.

Mr. Harrington also testified that it was not unusual to have a minimum take-or-pay obligation in a contract. GSU Ex. 77A at 20. He notes that the coal contracts at Nelson Six and Big Cajun II, Unit 3 have minimum take obligations which are recognized as reconcilable fuel costs. Similarly, the railroads and barge lines that deliver coal to those units are subject to minimum haul obligations which are also recognized as reconcilable. *Id.* at 21.

Based on the credible evidence, the fact that the arrangement allows SGT to pay off its capital costs in constructing the project and includes a minimum annual payment does not prevent GSU from seeking to include the SGT payments in the fuel factor.

iii. GSU has Option to Purchase

As noted above, GSU has the option to purchase the facilities, with a current market value of $40,000,000, from SGT for a sum equal to the Payoff Amount, provided that the purchase price is not less than one dollar. GSU witness Mr. Harrington testified that, although GSU would not permit the option to expire, it is unlikely that GSU would exercise its option because, under the present arrangement, SGT covers the liabilities and responsibilities of ownership while GSU receives the service provided by SGT. Tr. 2902-2903.

The existence of the option to purchase the facilities makes this arrangement with SGT truly unique but, like GSU's control over the project, does not require GSU to seek rate base treatment for the SGT payments.

***80** *iv. GSU Accounts for Project as a Capital Lease*

According to Financial Accounting Standards Board (FASB) Statement No. 13, a capital lease is one that, from the standpoint of the lessee, transfers to the lessee substantially all of the benefits and risks incidental to ownership of the leased property. A capital lease is accounted for by the lessee as the acquisition of an asset and the incurrence of a liability. OPC Ex. 56. [17] GSU categorizes the Spindletop gas storage facility as a capital lease. Mr. Willis testified that GSU has never requested that any of its other capital leases, including its nuclear fuel lease, be included in GSU's rate base. GSU Ex. 79 at 4; Tr. 2951, 2956. OPC argues that GSU's accounting method is another indicia of GSU's ownership of the facility, thereby requiring rate base treatment of the costs. Because GSU currently has not invested in the facility, is not required to invest, and is not required to exercise its option, rate base treatment at this point is uncertain, or at least speculative. The ALJ finds that merely because GSU accounts for the Sabine Spindletop facility as a capital lease does not require GSU to seek rate base treatment of the costs, if the costs otherwise are includible pursuant to the Commission's application of the Fuel Rule.

v. Cost of Project Would Have Been in Rate Base if GSU had Done the Project Itself

GSU denies that the costs associated with the Spindletop gas storage facility will be eventually included in GSU's rate base, although the final outcome appears to hinge on whether GSU's request to include the costs in the fuel factor in this case is granted. GSU Ex. 79 at 4; GSU Ex. 97, Sch. DNB-9.

GSU witness Mr. Harrington agrees with TIEC that if GSU had chosen to own and operate the storage facility itself, then GSU's investment would be included in rate base and a return included in base rates. According to Mr. Harrington, however, GSU did not have the means to build the facility itself, due to budgetary constraints. GSU Ex. 77 at 18; Tr. 2921-2922. Financial institutions would not provide financing for the project over the 30-year life of the project, but did offer a maximum 10-year period for financing. Tr. 2914-2915.

Whether the costs associated with the Sabine Spindletop facility would be included in rate base if GSU owned it and invested in it is not dispositive of whether the payments to SGT, *as currently structured*, are properly includible in the fuel factor. There is no guarantee that GSU will ever exercise the option to purchase the facilities. At this point, GSU does not expect to exercise the option and its future legal ownership of the facilities is speculative.

c. If Payments are Included in Fixed Fuel Factor, then Commission Is Precluded from Conducting Prudence Review

OPC advances an additional reason for not including the Sabine Spindletop facility costs in the fixed fuel factor. OPC witness Mr. Needler testified that the Commission should deny GSU's request to so include the Spindletop costs because a fuel reconciliation proceeding is not the proper forum in which to prove the prudence of a *rate base* item. OPC Ex. 45 at 18. He reasons the Commission could review the Spindletop facility's operation over a period of time in GSU's next rate case, rather than rely on GSU's forecasted data of expected savings to determine whether GSU had acted prudently in entering the agreement to 'purchase Spindletop.' *Id.* at 19.

***81** Mr. Needler's position assumes two things: (1) the Sabine Spindletop facility costs are rate base costs and (2) GSU has purchased the facility. Because the ALJ has found otherwise on both counts, the ALJ declines to alter her finding that the costs are properly includible under the Commission's application of its Fuel Rule.

d. Regulatory Lag

GSU continues to be subject to the base rate moratorium imposed in Docket No. 8702. If its merger with Entergy is approved in pending Docket No. 11292, GSU has apparently committed to not file a base rate case for five years. GSU Brief at 206. GSU argues that this combined period is not an ordinary case of regulatory lag, contending that the purpose of the Fuel Rule is to prevent such lag for *fuel-related* costs. Because the ALJ found that the payments to SGT are fuel-related costs properly includible in the fuel factor calculation pursuant to the Commission's application of the Fuel Rule in Docket Nos. 9300 and 8425, the ALJ does not need to reach the issue of whether extraordinary circumstances permit recovery of alleged *base rate costs* through the fuel factor.

C. Gas Inventory Carrying Costs

GSU estimates that its annual total system carrying costs on gas inventory stored in the Spindletop storage facility is approximately $311,200. GSU Ex. 43, Sch. DNB-3. GSU did not include these carrying costs in the fuel factor calculation filed with its application. Although GSU did not do so, the General Counsel recommended their recovery. GSU Ex. 43 at 9; General Counsel Ex. 14 at 20; General Counsel Ex. 10 at 22-23. GSU maintains that the carrying costs should be treated as reconcilable fuel costs under the Fuel Rule and the Commission's decision in Docket No. 8425, as discussed in Section VII.B. of the Report. If the Commission disagrees with GSU, GSU requests a good cause exception to P.U.C. SUBST. R. 23.21 to permit it to treat the carrying costs as reconcilable until GSU's next base rate case. GSU Ex. 43 at 9.

TIEC, OPC, and Beaumont argue that GSU is requesting an advisory order which would bind a future Commission to place Spindletop carrying costs in a future fuel factor or allow such costs to be treated as reconcilable in subsequent fuel reconciliation proceedings. Tr. 1282-1284. GSU witness Mr. Beekman agrees that approval of GSU's request will preclude a future Commission in a subsequent fuel reconciliation case from deciding that the gas inventory costs associated with Spindletop are not properly included in fuel but should be treated in another manner. Tr. 1283.

According to Mr. Beekman, GSU would record carrying costs on the average monthly balance of gas in the gas storage facility every month until GSU's next base rate proceeding. The expense would be treated as an underrecovery of reconcilable fuel costs because the fuel factor in this proceeding does not include those carrying costs. GSU Ex. 43 at 10. [18] Because GSU's request for reconcilable classification of the gas inventory carrying costs is premature, the ALJ recommends that the Commission deny the request. First, GSU did not request these costs and should not be permitted to include them in the reconcilable fuel balance for a future fuel reconciliation proceeding. Second, in response to the argument GSU is seeking an advisory opinion, GSU in brief stated that a Commission decision on this issue 'will effect the method by which the Company books these carrying costs and calculates its reconcilable fuel balance.' GSU Reply Brief at 106. Because the Spindletop facility was not in operation during the reconciliation period, however, the only logical conclusion is that GSU is referring to how it will calculate its reconcilable fuel balance *in the next fuel reconciliation proceeding*. Finally, GSU itself appears to believe that the carrying costs are base rate costs because it requests that they be treated as reconcilable *until its next base rate case* when, presumably, they would be placed in base rates. Indeed, GSU treats its other inventories of coal and fuel as base rate items. TIEC Ex. 10 at 27; Beaumont Ex. 14 at 58.

***82** Even if GSU is not requesting an advisory opinion, Beaumont argues that GSU's reliance on Docket No. 8425 is misplaced because the Commission there did not specifically address whether carrying costs on gas inventory should be treated as reconcilable fuel costs. Tr. 2187. In response, GSU contends that HL&P's payment for the North Dayton facility was a bundled fee and, therefore, it is unclear whether the bundled price included the carrying costs on the cushion gas in inventory. GSU Reply Brief at 107. GSU's argument hardly helps its position. If the Commission's decision in Docket No. 8425 did not clearly address the carrying costs, then it cannot very well support GSU's position.

Beaumont also argues that GSU's methodology for quantifying the carrying costs until its next base rate proceeding includes an improper federal income tax factor because GSU has paid federal income taxes only twice since 1986 and has $810,000 in tax loss carry forwards to use before 2004. Tr. 822; Beaumont Brief at 30. GSU disagrees, arguing that even if Beaumont correctly posits that it will pay no taxes, GSU's tax credits will be reduced by the amount of its tax liability on income to cover the carrying costs. GSU Reply Brief at 108. The evidence and argument on this issue, however, are sketchy at best. Consequently, the ALJ does not consider the issue to be litigated sufficiently to determine whether GSU has used an improper FIT factor.

GSU finally argues that a good cause exception is warranted because policy considerations support such. Because the carrying costs were not included in GSU's last rate case and may not be recoverable in base rates for another five years, GSU argues that it will incur carrying costs on the gas inventory without any benefit to its shareholders until such time they are included in rate base. GSU Brief at 209. There is no evidentiary showing sufficient to support GSU's request for a good cause exception. It has merely shown that it will experience some regulatory lag, partly of its own making. The ALJ declines to recommend a good cause exception without stronger evidentiary support.

D. Incentive Rates

Consistent with the ALJ's recommendation in Section VI.B. of the Report that the expense from incentive rates be excluded from the reconcilable fuel balance, the ALJ recommends that those expenses also be excluded from the fuel factor calculation, as proposed by GSU and the General Counsel.

E. Off-System Sales Adders

GSU did not include any off-system sales in its proposed fuel year. It does not project off-system sales in the absence of firm sales agreements, of which GSU has none for its projected fuel year. GSU Ex. 29 at 8; Calvert Ex. 24, Sch. DSN-14. Mr. Beekman contends that because off-system sales are difficult to predict, GSU cannot agree that an estimated level of off-system sales should be included in the fixed fuel factor calculation. GSU Ex. 97 at 56-59.

In the event the Commission accepts GSU's proposed historical treatment of adders as non-reconcilable and it decides that off-system sales adders should be treated as reconcilable on a prospective basis, GSU agrees that a sharing of the profit on a 75/25 percentage basis between the ratepayers and shareholders is appropriate. Under these circumstances, GSU proposes that the actual off-system sales and adders be calculated monthly, and the appropriate percentage booked to the reconcilable fuel balance. The adders would be prospectively reconciled from the date of the final order in this docket. GSU still disputes, however, that an estimated level of adders should be included in the fuel factor. GSU Brief at 209-210.[FN24]

***83** Calvert takes exception to GSU's position that off-system sales are difficult to predict, noting that GSU made off-system sales for the last 17 years and averaged over 438,000 MWH per year during that period. Calvert Ex. 24 at 17-18; Sch. DSN-15. During the reconciliation period, GSU averaged 303,542 MWH in off-system sales per 12-month period. Mr. Norwood recommends that the fuel year system reconcilable fuel projection be adjusted to include off-system sales revenue of $1,424,000 based upon the average level of sales and profit for the reconciliation period. Calvert Ex. 24 at 18.[FN25]

OPC also recommends that off-system sales adders be included in the fuel factor calculation, but offers a slightly different adjustment. To recognize GSU's off-system sales in the fuel factor, OPC witness Mr. Needler recommends that an adjustment be included in the fixed fuel factor calculation, based on an annualization of GSU's total sales through May 1992. OPC Ex. 45 at 23-26. Based on sales of $923,440 through May 1992, OPC's recommended adjustment is $2,216,256. OPC Brief at 93.

Given that GSU made off-system sales every year since 1970 and has averaged at least 438,000 MWH of off-system sales in the last 17 years, its contention that such sales are difficult to predict is certainly questionable. Calvert has made a persuasive argument that these sales are, at the very least, *reasonably predictable*, which is sufficient for inclusion in the fixed fuel factor calculation. P.U.C. SUBST. R. 23.23(b)(2)(B) and (C).

The ALJ recommends that the off-system sales adders be recognized in the fixed fuel factor calculation, as recommended by Calvert witness Mr. Norwood. Because prospective treatment is at issue here, there is a plausible policy argument in favor of splitting the adders between the ratepayers and shareholders to provide the utility with an incentive to pursue off-system sales above the test year level; otherwise, any off-system sale on a going-forward basis is a net loss unless GSU can recover the variable costs incurred by the sale. GSU Ex. 97 at 58-59. Therefore, the ALJ recommends that the adders be split between the ratepayers and shareholders 75/25 percent in favor of the ratepayers, as recommended by General Counsel witness Ms. Schultz.

F. Purchased Power

GSU included $82,862,267 in purchased power costs in its projected fuel year. Of this amount, $62,423,142 constitutes the NISCO-related purchase power expenses discussed in Section VII.G. of the Report, leaving $20,439,125 of non-NISCO purchased power payments in GSU's projected fuel year. GSU Ex. 39, Sch. FF.C-2 at 7. The remaining purchased power expenses consist of energy associated with GSU's buyback agreement for Nelson 6 with Sam Rayburn Municipal Power Agency (SRMPA), replacement energy purchases from Entergy, and purchases from the Toledo Bend Dam and various cogeneration sources. GSU Ex. 39 at 8.

Calvert argues that the Commission should adjust Mr. Neeley's estimated purchased power expense because he did not include any generation from the Toledo Bend Dam in his estimate. In fact, Mr. Neeley did not include any other purchased power in his estimate other than the NISCO-related purchased power payments. Tr. at 2172-2173. Calvert believes that it is more reasonable to project that GSU's Toledo Bend purchases will be similar to GSU's proposal than to assume that those purchases will be zero.

***84** Therefore, Calvert recommends that the costs of Toledo Bend Dam purchases for the fuel year be the same on a monthly basis as those proposed by GSU. Calvert Brief at 72. In other words, for January **1993** through June **1993**, the Toledo Bend purchases would be as shown in GSU's Schedule FF.C-2. GSU Ex. 39, Sch. FF.C-2 at 4-6. For July **1993** through December **1993**, the Toledo Bend purchases would be assumed to equal the purchases shown for July 1992 through December 1992. *Id.* at 1-3. The end result is that Calvert urges adoption of GSU's projected Toledo Bend purchases. *Id.* at 7.

To account for the change in plant utilization, Calvert also proposes a corresponding reduction in the amount of energy generated from GSU's gas-fired plants. It provided a schedule showing Calvert's recommended adjustment to the General Counsel's fuel year. Calvert Brief, Appendix I. The total recommended reduction to the General Counsel's fuel and purchased power costs is $1,085,419.

GSU disagrees with Calvert's proposed adjustment to Mr. Neeley's calculation of purchased power. Because Mr. Neeley used only the NISCO costs in calculating purchased power costs, omitting the Toledo Bend and Agri-electric costs, GSU urges the Commission to adopt its proposed test year and fuel factor. GSU Reply Brief at 108.

If the Commission adjusts Mr. Neeley's purchased power expense, however, GSU argues that it should not use Mr. Bivens' average gas costs to determine the fuel factor as Calvert has done. GSU contends that Calvert's use of average gas prices is higher than the actual costs of gas that Toledo Bend would displace because Toledo Bend would displace spot gas, which is less expensive than long-term gas. GSU contends, however, that if the Commission adjusts Mr. Neeley's purchased power calculation, it should adjust it to account for all purchased power. The Commission could accomplish this adjustment by annualizing GSU's purchased power number for the first six months of **1993** and adjust Mr. Neeley's gas usage to account for the extra Toledo Bend power. GSU Ex. 39, Sch. FF.C-2 at 7; GSU Reply Brief at 109.

Because the General Counsel did not file a reply brief, the ALJ does not know what its position is regarding Calvert's or GSU's proposed changes to the General Counsel witness' calculation of purchased power. The ALJ agrees that Mr. Neeley's proposed purchased power cost should be adjusted to account not only for Toledo Bend power, as urged by Calvert, but also for other power purchases, as proposed by GSU. To make this adjustment, GSU's purchased power estimate for the first six months of **1993** should be annualized, and Mr. Neeley's gas usage should be revised accordingly. The ALJ cannot adopt Calvert's recalculation because it accounts only for Toledo Bend power.

G. NISCO

GSU included 100 percent of its NISCO purchased power payments, or $62,423,142, in its projected fuel year. GSU Ex. 43 at 7; GSU Ex. 39, Sch. FF.C-2 at 7. Beaumont, OPC, and TIEC recommend that all NISCO costs above avoided cost be removed from the fixed fuel factor calculation. Based on NISCO payments of $62,423,142 for the fuel year, the amount above avoided cost is $36,890,000 on a total company basis, or $16,603,865 for GSU's Texas jurisdiction. TIEC Ex. 10b, Sch. 2; OPC Ex. 45a, Sch. REN-1 Revised. For the reasons stated in Section V.C. of the Report, the ALJ recommends that the portion of GSU's NISCO payments above avoided cost be excluded from the fixed fuel factor calculation.

H. Projected Utilization of Power Plants

***85** Calvert, GSU, and the General Counsel address the issue of projected utilization of GSU's power plants during the fuel year. Calvert recommends that the projected use of Big Cajun II, Unit 3 be increased to account for the lower costs of incremental coal. Calvert Ex. 23B at 55-57. GSU agrees that it will use Big Cajun to a greater degree because of the relatively low cost of coal there. GSU Ex.

76A at 28; GSU Reply Brief at 110.

Because Calvert supported adoption of the General Counsel's fuel year, it recommends adjustments to Mr. Neeley's projected generation to account for the increase in utilization of Big Cajun II, Unit 3. To adjust Mr. Neeley's projections, Calvert supplied a calculation in its initial brief to demonstrate how the recommended adjustment would be made. Calvert Brief, Appendix II.

Calvert argues that the appropriate manner in which to adjust Mr. Neeley's projection is by reducing the General Counsel's projected generation at Nelson 6 and replacing it with generation at Big Cajun, Unit 3. Calvert's recommendation required three adjustments to Mr. Neeley's projected utilization:

1. Nelson 6 coal purchases on a plant basis were reduced to 2.25 million tons; 2. The reduction in generation at Nelson 6 was made up with generation from Big Cajun; and 3. Big Cajun coal was priced according to Calvert witness Ms. Pitchford's projections in her workpapers (Calvert Ex. 23D at 'Big Cajun Dispatch: Fuel Year').

According to Calvert's brief, this last adjustment was necessary to account for the incremental pricing in the Big Cajun coal supply, barge, and rail contracts. Calvert Brief at 74.

While GSU agrees that its utilization of Big Cajun II, Unit 3 will increase and that Calvert's calculated 66.14 percent capacity factor for that unit is not unreasonable, it disagrees that the increase in Big Cajun generation will displace Nelson 6 generation. GSU Reply Brief at 110. Instead, GSU argues that Big Cajun generation will offset spot gas purchases because the cost per MMBtu of spot gas is less than Nelson 6 generation.

The increase in dispatch of Big Cajun II, Unit 3 is not contested and the General Counsel's fuel year should be modified accordingly. The ALJ cannot adopt Calvert's proposed redispatch, however, because it is based on the premise that GSU is entitled to incremental pricing under the JOPOA. The ALJ rejected Calvert's position on incremental pricing in Section V.B.1. of the Report. The ALJ therefore adopts GSU's position that the increase in Big Cajun II, Unit 3 generation will offset spot gas purchases.

I. Jurisdictional Allocation

GSU allocated total company expenses to the jurisdictions based on allocation factors, which were in turn based on KWH consumption at the meter. GSU Ex. 29A, Sch. FR.C-10 at 1-7, line 17. General Counsel witness Mr. Jeffry Rosenblum contends that it is more appropriate to use allocation factors based on consumption at the plant because fuel costs are a function of generation, not sales, and the line losses from the different jurisdictions are not always the same. General Counsel Ex. 12 at 4-6. He recalculated the allocation factors using at-plant data.

***86** GSU apparently does not contest Mr. Rosenblum's adjustment using at-plant data, but argues that he should not have included the effects of company use and reserve station service in developing his jurisdictional allocator. Mr. Rosenblum agrees with GSU's position on this matter. Tr. at 2388.

The ALJ recommends that the jurisdictional allocator be calculated using at-plant data, but excluding the effects of company use and reserve station service. Based on the ALJ's recommendations in this docket, this results in a jurisdictional allocator to the Texas jurisdiction of 45.01 percent.

J. Municipal Expenses

GSU requests that any of the cities' litigation expenses incurred in this docket which the Commission requires GSU to reimburse be treated as a reconcilable fuel expense and included in the fixed fuel factor calculation. This issue is discussed in Section VIII. of the Report regarding the reasonableness of the cities' requested litigation expenses.

K. ALJ's Recommended Fixed Fuel Factor

Based on the above discussion, the ALJ's recommended fixed fuel factor is $0.018545/KWH.

VIII. Municipal Expenses

A. General Background and Examiner's Order No. 12

Earlier in this proceeding, Beaumont requested monthly reimbursement of its reasonable expenses associated with this docket, pursuant to PURA § 24(a). Calvert subsequently joined in Beaumont's request. GSU opposed the cities' requested monthly reimbursement of litigation expenses.

In Examiner's Order No. 12, issued May 13, 1992, the ALJ found that this was a ratemaking proceeding and concluded that the cities were entitled to reimbursement of reasonable expenses pursuant to PURA § 24(a). While the language of PURA § 43(g)(2)(C) exempts fuel proceedings from the requirements of PURA § 43(a), there is no reference there to PURA § 24(a). Consequently, there is no basis for arguing that the language of PURA § 43(g)(2)(C) prohibits the cities from recovering reasonable expenses in fuel reconciliations under PURA § 24(a).[FN26] As a result, the ALJ found that PURA § 24(a) does not limit reimbursement of reasonable expenses to § 43 proceedings and that PURA § 43(g)(2)(C) does not prohibit the reimbursement of the cities' reasonable expenses under PURA § 24(a). GSU appealed the ALJ's order, but the Commission declined to hear the appeal.

Pursuant to Examiner's Order No. 12, GSU was ordered to reimburse the cities, on a monthly basis, for 90 percent of their monthly expenses related to this docket. The following guidelines applied before monthly reimbursements were allowed:

1. The participating cities shall review all invoices and certify their reasonableness prior to reimbursement. No monthly payment shall be made by GSU for invoices not certified as reasonable by the cities.

2. The invoices and supporting documents shall contain the following information:

a. the individual charges and rates; b. the amount of each service (*e.g.*, the hours billed); c. the calculation of the charges; and d. a brief, specific description of the services performed.

***87** All of the cities' expenses were to be reviewed for reasonableness during the rate case expense phase of this docket. The cities were required to refund any amounts paid to them by GSU above the levels ultimately found reasonable by the Commission.

The ALJ imposed the following standards in determining the reasonableness of the cities' rate case expenses:

1. The testimony of each witness offered to support rate case expenses must expressly state that the witness has informally audited the invoices and other documentation. A cursory review is not sufficient, and expense items are not to be presumed reasonable.

2. Based on their review of the documents, the witnesses must affirm that:

a. the individual charges and rates are reasonable, *e.g.*, by comparison with the usual charges for similar services; b. the amount of each service (*e.g.*, hours billed) is reasonable; c. the calculation of the charges is correct; d. there is no double-billing of charges; e. none of the charges in rate case expenses has been recovered through reimbursements for other expenses; f. none of the charges in rate case expenses should have been directly assigned to other jurisdictions; and g. any allocation of charges between jurisdictions is reasonable, *e.g.*, on the basis of commonly accepted criteria stated in the testimony.

3. Witnesses testifying in support of rate case expenses should attach exhibits to their testimony that itemize the expenses by categories, major consulting firms, and law firms.

4. One witness should provide a summary of the total expenses for which reimbursement is sought, and compare the total to the dollars at issue in the docket.

In its pleadings opposing the initial request for reimbursement, GSU questioned whether two groups of intervening cities could recover reasonable expenses in the same case. The ALJ found that the mere fact there were two groups of intervening cities did not bar reimbursement. The Commission has previously ordered a utility to reimburse two intervening groups of cities.[FN27] In Examiner's Order No. 12, the ALJ concluded that the issue of whether the two groups had unreasonably duplicated efforts, as alleged by GSU, was a matter to be determined based on the evidence adduced during the rate case expense phase of this proceeding. GSU did not raise this issue during the hearing and the presentation of the case confirms that Calvert and Beaumont did not duplicate their efforts. Additionally, GSU stated that it intended to request recovery of any reimbursed litigation expenses through a bill surcharge to the residents of the cities incurring the expenses. Because GSU did not formally request authority to implement such a surcharge, the ALJ did not rule on that issue in Examiner's Order No. 12.

B. The Reasonableness of the Cities' Actual Expenses and the Cities' Request for Estimated Expenses

Beaumont and Calvert request the following actual and estimated expenses relating to their participation in this docket:[FN28]

Party	Requested[FN*] Actual Expenses	Estimated Future Expenses	Total
Beaumont	$ 341,820.66	$ 83,179.34	$ 425,000.00
Calvert	276,495.63	128,327.60	404,823.23
Total	$ 618,316.29	$ 211,506.94	$ 829,823.23

* The actual expenses are through October 31, 1992.

***88** GSU takes no position regarding the reasonableness of the expenses incurred by the two groups of cities. And except for a few minor disallowances recommended by General Counsel witness Ms. Schultz, no party contests the amount of actual expenses incurred by the cities through October 1992. Ms. Schultz does not recommend the reimbursement of the cities' estimated expenses. She recommends, however, that the cities continue to file information supporting the expenses after October 31, 1992, in this proceeding.

Beaumont witness Mr. Pous testified with regard to Beaumont's requested rate case expenses, including the expenses for his consulting firm, Diversified Utility Consultants, Inc. (DUCI). Beaumont Ex. 44; Beaumont Ex. 43A. His revised testimony covers the period beginning with the retention of outside assistance by Beaumont through October 31, 1992, on an actual basis, and on an estimated basis for the balance of the proceeding and subsequent court proceedings.

Mr. Pous affirmed that he informally audited the invoices and other documentation submitted by the law firm of Butler, Porter, Gay & Day (BPGD). Based on his review, he found that the individual rates are reasonable when compared to charges for similar services, and that the amount of the service or hours billed is reasonable. He noted that the hourly rate for attorneys of BPGD is $150 per hour.

His audit did not identify any errors in the calculation or any double billing of charges. He did not identify any instance in which any of the charges had been recovered through reimbursement of other expenses or through billings to other entities. He testified that he reviewed the law firm's bills, time sheets, and billing procedures, and discussed the expenditures with personnel of the firm. Beaumont Ex. 44 at 5.

Beaumont requests that it be reimbursed $425,000 for its actual and estimated legal and consulting expenses in this proceeding. Beaumont Ex. 44 at 2. Of the requested $425,000, $225,000 constitutes legal fees and expenses incurred by BPGD.

The actual amount of rate case expenses incurred by BPGD through October 31, 1992, is $154,711.53. This amount is comprised of $141,063 in fees and $13,648.53 in out-of-pocket expenses. The projected expenses for legal representation through the completion of this docket and subsequent court proceedings is estimated to be $225,000. The estimated amount includes $40,000 associated with anticipated appeals and $2,793.64 for transcript costs. The estimate also includes $154,711.53 actually incurred through October 1992. *Id.* at 3; Beaumont Ex. 43A. Based on his review, Mr. Pous testified that Beaumont's estimated legal costs of $225,000 are just and reasonable and should be reimbursed by GSU. *Id.* at 6.

DUCI incurred fee-related charges of $179,906.25 and expenses of $7,202.88 through October 1992. Therefore, the total level of actual charges through October 1992 for DUCI is $187,109.13. DUCI estimated that the total level of charges for this case would be $200,000. The estimated amount is comprised of $192,500 in fees and $7,500 in out-of-pocket expenses and includes the actual fees and expenses incurred through October 1992. *Id.* at 7.

***89** DUCI's overall average hourly labor rate is approximately $95 per hour. Mr. Pous believes that this composite labor rate is very reasonable and low when compared to other consulting firms who perform similar activities on behalf of their clients in utility rate proceedings. Beaumont Ex. 44, Sch. JP-RCE-2. Mr. Pous informally audited the invoices and other documentation of DUCI; this audit did not identify any errors in the calculation or any double billing of charges. Further, he found no instances in which the charges have been recovered through reimbursement of other expenses. Revised Schedule JP-RCE-3 sets forth Beaumont's requested $425,000 for legal and consulting expenses. Beaumont Ex. 43A, Sch. JP-RCE-3 Revised. Of this amount, Mr. Pous testified that there are no expenses or charges that should be assigned to another jurisdiction. Beaumont Ex. 44 at 10.

Calvert witness Mr. James Daniel testified regarding the requested rate case expenses of Jo Campbell, counsel for the Calvert, and of the consulting firm retained by Calvert, GDS Associates, Inc. (GDS). Calvert Ex. 45; Calvert Ex. 45A.

Through October 1992, the charges for services provided by Jo Campbell to Calvert is $100,702.05. The estimate of charges for services for the remainder of this case and any subsequent court proceedings is $93,100. Therefore, the total charges, actual and estimated, for legal services rendered on Calvert's behalf is $193,802.05. Calvert Ex. 45A at 2.

Calvert witness Mr. Daniel performed an informal audit of Ms. Campbell's invoices and other supporting documents and verified the accuracy of the charges shown on the invoices. The invoices contain a description of the services performed and the hours charged by day. He confirmed that there was no double billing of charges, none of the charges had been recovered from other sources, and none of the charges should have been billed to others. He notes that through July 1992, Jo Campbell charged Calvert only for her time, and has not requested reimbursement for travel expenses or other out-of-pocket expenses. Calvert Ex. 45 at 14.

Mr. Daniel testified that Jo Campbell's $150 per hour fee is very reasonable given her prior experience, and compares favorably with hourly fees charged by other attorneys providing similar service. Calvert Ex. 45 at 11; Sch. JWD-1. He considers the number of hours expended so far, and the estimated number of additional hours required, to be reasonable.

Mr. Daniel also provided testimony regarding the reasonableness of the fees and expenses charged by GDS to Calvert in this proceeding. The hourly rates of GDS personnel assigned to this case ranged from $28 per hour to $140 per hour. He states that the GDS rates compare favorably with a survey of similar consulting firms in the utility consulting business. *Id.* at 17; Sch. JWD-3. He performed an informal audit of GDS's invoices and supporting documentation, revising one invoice to delete $360 from the amount of GDS' expenses. Tr. 4093-4094, 4097-4098. He confirmed that there was no double billing of charges, none of the charges had been recovered from other sources, and none of the charges should be billed to others.

***90** Through October 1992, GDS's charges total $176,153.58. The estimate of additional expenses for the duration of this docket is $35,227.60. This estimate includes $3,700 in professional fees for services rendered during October 1992, which were omitted from the October invoice. Based upon the updated estimate, GDS's total charges are $211,381.18. Calvert Ex. 45A at 2. According to Mr. Daniel, the bulk of the estimated additional expenses are for post-hearing tasks such as preparing the initial brief and reply brief, reviewing the Examiner's Report, preparing the briefs on exceptions and replies, preparation and presentation of oral arguments, preparation of motions for hearing and responses thereto, and for participation in any appeals. *Id.* at 3. The total amount of Calvert's requested rate case expenses for legal and consulting services, including additional estimated expenses, is $405,183 minus $360, or $404,823.23. *Id.*, Sch. JWD-4.

General Counsel witness Susan Schultz reviewed the invoices and supporting documentation provided by Beaumont and Calvert. For professional services, Ms. Schultz requires a brief, specific description of the work performed, the number of hours worked, and the hourly billing rate for each individual for which reimbursement was requested. For travel expenses, she requires a copy of the original invoice or receipt. For internal expenses such as copying or supplies, she requires documentation indicating quantity and the total amount charged. General Counsel Ex. 15 at 2.

Ms. Schultz verified the arithmetical accuracy of the invoices, receipts, and supporting documentation. She did not find any evidence of double billing of charges. With two limited exceptions, she found the requested expenses and individual hourly billing rates to be reasonable. *Id.* at 3.

Ms. Schultz' recommended actual rate case expenses through October 1992 and the cities' estimated expenses are as follows:

Party	Recommended Actual Expenses
Beaumont	
Legal	$ 154,702.47
DUCI	187,071.63
Total	$ 341,774.10
Calvert	
Legal	$ 100,702.05
GDS	175,793.58
Total	$ 276,495.63 =
Grand Total	$ 618,269.73

Ms. Schultz adjusted Beaumont's and Calvert's actual requested rate case expenses with minor adjustments. General Counsel Ex. 15B. She recommends that $154,702.47 in legal fees and expenses, and $187,071.63 in engineering fees and expenses be reimbursed to Beaumont, for a total of $341,774.10. With regard to Calvert, Ms. Schultz recommends $100,702.05 in legal fees and expenses, and $175,793.58 in engineering fees and expenses, for a total of $276,495.63. In total, her recommended reimbursement of actual rate case expenses for the two intervening city groups is $618,269.73. General Counsel Brief at 47.

Ms. Schultz does not recommend reimbursement of the cities' estimated expenses. Instead, she recommends that the cities file invoices for the period subsequent to October 1992, using the same guidelines and documentation levels established in Examiner's Order No. 12, starting 30 days following the close of the hearing. She suggested that interested parties review the information and request a hearing within two weeks of filing only if they questioned the reasonableness of any of these expenses. *Id*. at 6. The ALJ has not received any filings, either from the cities nor from other parties, questioning the accuracy or the reasonableness of additional invoices, if any. The ALJ therefore has no opinion with regard to the additional invoices, if any, that have been provided subsequent to the adjournment of the hearing.

***91** Except for a $9.06 disallowance for Beaumont and a $360 voluntary reduction by Calvert, no party contests the reasonableness of cities' actual incurred expenses and fees through October 1992. The cities have complied with the standards adopted by this Commission and the ALJ in Examiner's Order No. 12. Therefore, based on Commission precedent, there is no legal basis for not recommending approval of the cities' actual incurred rate case expenses through October 1992, as modified by Calvert during the hearing and as recommended by Ms. Schultz.

The Commission's treatment of rate case expenses, with regard to their reasonableness and accuracy and the policy issues underlying their purpose and efficacy in promoting the cities' participation in Commission proceedings, has developed on a case-by-case basis. While such an approach may permit latitude by which the Commission can fashion a recommended level of expenses, the lack of a written policy or rule hinders the Commission staff in their review, the ALJs and the examiners in their deliberations, and precludes a consistent approach to rate case expenses in different types of cases involving different utilities, intervening cities, law firms, and consultants. As long as the cities' expenses are for the most part reimbursed by the utilities and the utilities can pass those costs on to their ratepayers, no party has any real *monetary incentive* to hold the line on the level of rate case expenses. The Commission staff does the best it can to evaluate the expenses incurred and review them for arithmetical accuracy, but the ultimate policy determination of reasonableness lies with the Commission itself. There is no easy answer, particularly when the decision regarding rate case expenses affects the level of participation in the case and some of its participants' livelihoods. For these reasons, the ALJ hopes that the long-promised rulemaking relating to rate case expenses would again be moved to the forefront by the Commission.

C. GSU's Request that the Reimbursed Litigation Expenses be Treated as a Reconcilable Expense and Included in the Fuel Factor Calculation

GSU requests that any cities' litigation expenses it must reimburse in this proceeding be included in the fuel factor and recovered as fuel-related expenses. GSU's request was opposed by General Counsel witness Ms. Schultz,[FN29] TIEC, Beaumont, and Calvert.

GSU first argues that the cities' expenses are fuel-related expenses because they would not exist but for the need to reconcile GSU's fuel costs in this case. TIEC correctly points out, however, that although the parties' activities in this proceeding may indeed affect the amount that GSU recovers from its ratepayers, they do not directly affect the prices that GSU pays in acquiring fuel. TIEC Reply Brief at 35.

GSU also argues that Commission precedent does not prohibit approval of its request. In Docket No. 9030, however, the Commission found that the utility's expenses incurred as a result of processing a fuel reconciliation proceeding were not fuel-related costs. *Petition of General Counsel For a Fuel Reconciliation For Southwestern Public Service Company*, Docket No. 9030, 17 P.U.C. BULL. 395, 460-461, 471 (June 3, 1991). GSU acknowledges the Commission's holding in Docket No. 9030, but insists it is not controlling in light of the Commission's more recent decisions in Docket Nos. 10035 and 9300.

***92** In Docket No. 10035, the Commission approved a stipulation in a fuel reconciliation proceeding which included the intervening city's rate case expenses as fuel-related costs. *Application of West Texas Utilities Company to Reconcile Fuel Costs and For Authority to Change Fixed Fuel Factors*, Docket No. 10035, 17 P.U.C. BULL. 545 (Sept. 30, 1991) (mem.). Docket No. 10035, however, does not support GSU's position. TIEC, Calvert, and Beaumont correctly argue that this docket is not precedential because it was a stipulated case.

GSU further argues that the cities' rate case expenses fall under the Commission's decision in Docket No. 9300 holding that all known or reasonably predictable fuel costs, whether fixed or variable, which are not specifically excepted by the Fuel Rule should be included in the fixed fuel factor. However, the issue in Docket No. 9300 did not concern whether an expense was fuel-related or not. Rather, it involved whether the expense was fixed or variable.

Finally, GSU contends that the cities' expenses in this case are significant, and it is not currently recovering such an expense through base rates. Therefore, GSU urges the Commission to reject the argument that the cities' expenses are base rate costs that can only be recovered through a rate case. This argument goes to the heart of GSU's concern: the lag time between reimbursing the cities for these expenses and the time GSU can eventually recover the expenses in a rate case.

If the Commission finds that the cities' litigation expenses must be recovered through base rates only, GSU cannot recover them for a long time, if at all. As stated earlier, GSU is still under the base rate moratorium agreed to in Docket No. 8702. In addition, in its pending application for approval of its merger with Entergy in Docket No. 11292, GSU has committed to not file a base rate case for five years. There is no guarantee that a utility will not suffer some regulatory lag from time to time. Admittedly, five years is a long time, but the situation is of GSU's own making.

TIEC and Calvert dispute GSU's argument that it is not recovering a significant level of rate case expenses through its base rates under the stipulation in Docket No. 8702. Because the ALJ finds that the cities' litigation expenses in this case are not fuel-related expenses, the she does not need to reach the issue of whether GSU is underrecovering or overrecovering certain rate case expenses under the stipulation entered in Docket No. 8702.

Finally, the ALJ notes that the General Counsel argues in brief that the Commission may allow GSU to recover the reimbursed rate case expenses through the fuel factor as a matter of policy, contending that to do otherwise would inhibit participation by the cities in fuel reconciliation proceedings. General Counsel Brief at 46. As noted by TIEC in brief, the General Counsel's concern is misplaced. The cities already have an incentive to participate in fuel reconciliation proceedings because the Commission has held that fuel reconciliation proceedings are ratemaking proceeding for the purposes of reimbursement of reasonable rate case expenses. Allowing GSU to recover the expenses through the fuel factor would not necessarily provide any incentive to the cities to intervene.

***93** As a final shot across the bow, Calvert argues that the Commission should establish a policy in which the utility would forfeit its right to recover rate case expenses if it has, in any manner, opposed a city's participation at either the municipal or Commission level. Calvert Reply at 93. While perhaps a novel idea, the ALJ questions its legality and declines to recommend adoption of Calvert's proposed policy. [19] Based on the Commission's decision in Docket No. 9030, the ALJ recommends that the Commission deny GSU's request to recover the cities' reimbursed litigation expenses through the fixed fuel factor.

IX. Findings of Fact and Conclusions of Law

The ALJ recommends the Commission adopt the following findings of fact and conclusions of law:

A. Findings of Fact

1. On January 21, 1992, Gulf States Utilities Company (GSU) filed an application requesting reconciliation of its fuel and purchased power costs during the reconciliation period beginning October 1, 1988, through September 30, 1991, with the exception of: (1) NISCO purchased power expense, for which the beginning of the fuel reconciliation period is September 15, 1988; and (2) Nelson Unit 6 rail transportation costs under contracts with Burlington Northern Railroad Company and Kansas City Southern Railway Company (the Railroads), for which the beginning of the fuel reconciliation period is December 1, 1986.

2. GSU published notice of this proceeding once each week for four consecutive weeks in newspapers of general circulation in each county containing territory affected by the proposed changes. In addition, GSU provided direct notice to its customers by bill insert, and mailed notice to the mayors

and city councils of the affected municipalities, and to the county judges and commissioners of the affected counties.

3. The Office of Public Utility Counsel (OPC), Texas Industrial Energy Consumers (TIEC), North Star Steel, the City of Beaumont, et al. (Beaumont), the City of Calvert, et al. (Calvert), and the General Counsel participated in the proceeding. The hearing convened on October 1, 1992, and was finally adjourned on November 6, 1992. There is no jurisdictional deadline in this case.

4. The booked cost of gas purchased from UTTCO during September 1991 was $3.14/MMBtu. The actual cost of gas purchased from UTTCO during September 1991 was $1.7509/MMBtu. Consequently, the booked cost of gas exceeded the actual cost by $434,262. GSU credited the $434,262 as a prior period adjustment (PPA) in October 1991 which would be addressed in GSU's next fuel reconciliation proceeding.

5. There is no credible evidence that the UTTCO PPA was intended to increase cash flow.

6. If all the PPAs for October 1991 had been applied to the September 1991 balance, GSU's underrecovery balance would have increased by $925,938.

7. The UTTCO PPA should not be adjusted in this fuel reconciliation proceeding. Absent evidence which would suggest intentional wrongdoing, PPAs should be adjusted during the appropriate fuel reconciliation period and not outside that period.

***94** 8. GSU's minimum take obligation under the Exxon contract is based on a daily average over a six-month period. If GSU does not take the minimum over that period, it has to pay a take-or-pay penalty. Therefore, to avoid that penalty, GSU must carefully plan its gas take over the six-month period.

9. Going into December 1989, GSU had balanced its purchases under the Exxon contract such that, if GSU had taken the minimum obligation for the month of December 1989, it would not have incurred a take-or-pay penalty.

10. GSU could not have foreseen the extreme harshness of the weather in late December 1989 and the resulting increase in demand.

11. GSU reasonably balanced its takes under the Exxon contract for the six-month period ending December 1989.

12. GSU did not specifically rebut Mr. Bivens' proposed disallowances with respect to the Rotherwood/Eastex contract, and his proposed disallowance for the Exxon contract for June 1989 and December 1990. These disallowances should be adopted, resulting in a disallowance of $18,500 on a total company basis.

13. Big Cajun II consists of three 540 MW coal-fired generating units. Cajun Electric is the majority owner and operator at Big Cajun. GSU is a joint owner with a 42 percent undivided ownership interest (or 227 MW) in Big Cajun II, Unit 3.

14. The coal supply for the unit is purchased by Cajun Electric under a coal supply contract with Triton Coal Company (Triton), a subsidiary of Shell Oil. The coal is transported to Big Cajun under transportation agreements between Cajun Electric and Burlington Northern and American Commercial Terminals, Inc.

15. GSU receives its portion of the coal purchased by Cajun Electric under the terms of the Joint Ownership Participation and Operating Agreement (JOPOA) for Big Cajun II, Unit 3 executed between GSU and Cajun Electric.

16. Just prior to the beginning of, and during, the reconciliation period, Cajun Electric negotiated with the coal supplier and transporters for incremental coal in excess of the minimum contract

requirements to be purchased and delivered at reduced incremental prices.

17. Cajun Electric did not allow GSU to benefit from this lower-priced incremental coal.

18. As a result of GSU's exclusion by Cajun Electric from the benefits of this lower-priced incremental coal, GSU's ratepayers will pay higher coal prices.

19. GSU first learned of Cajun Electric's October 1987 contract with Triton for incremental coal purchases in late 1987.

20. From October 1987 through mid-1991, Cajun Electric continued to enter into contracts or agreements for incremental coal purchases and pricing to the exclusion of GSU. Similarly, Cajun Electric was able to procure incremental rail and barge rates to GSU's exclusion.

21. GSU did not always get timely information from Cajun, and frequently was not permitted to review the contracts in an unedited form.

22. On November 8, 1990, GSU filed an amended counterclaim against Cajun Electric in U.S. District Court, Middle District of Louisiana, alleging that Cajun Electric violated its fiduciary duties as agent to GSU, and had breached the terms of the JOPOA, by not allowing GSU to benefit from the lower-priced incremental coal.

***95** 23. It is appropriate to defer ruling on the incremental coal issue until the federal litigation is concluded, whether by order of the court, by settlement of the parties, or other manner. GSU should be required to include the proceeds of any recovery from Cajun Electric, net of associated litigation costs, as an adjustment to the over- or underrecovery balance of reconcilable fuel costs that exists at the time any such recovery is received. The regulatory treatment of any net recovery will be subject to Commission review.

24. GSU renegotiated the rail transportation contract for Nelson 6 during the reconciliation period. Negotiations began on June 6, 1989, the earliest possible date under the 1984 rail transportation contract. These discussions continued until August 13, 1990; on February 26, 1991, they began again.

25. Price adjustments under the Nelson 6 rail transportation contract are made on a quarterly basis, and the effective date of any amendment during the renegotiation is the first day of the subsequent calendar quarter.

26. If negotiations had resumed before January 1, 1991, then that date would have been the operative effective date for any amendments.

27. Negotiations had reached an impasse in August 1990.

28. The Railroads would not negotiate the provision giving the Railroads the exclusive right to deliver coal to Nelson Station.

29. The finalized contract will be between $19 million and $22 million less than the Railroads' earlier proposals.

30. GSU handled the renegotiation of the Nelson 6 rail transportation contract in a reasonable manner.

31. By agreement of the parties in GSU's last rate case, the cost of transporting coal to Nelson 6 was deferred until the next fuel reconciliation proceeding. *Application of Gulf States Utilities Company for Authority to Change Rates*, Docket No. 8702, Finding of Fact Nos. 52 and 55, 17 P.U.C. BULL. 703, 1004-1005 (March 22, 1991). The amount to be reconciled is $59,797,402 for the period December 1986 through September 1988. Because no party to this docket recommended a disallowance of these costs, no disallowance should be imposed.

32. In 1988, GSU transferred two gas-fired units from its Nelson Generating Station in Lake Charles, Louisiana, to the Nelson Industrial Steam Company (NISCO), a general partnership organized under the laws of the State of Texas. The NISCO partnership includes GSU and three industrial customers (the Industrial Participants): Citgo Petroleum Company (Citgo); Conoco, Inc. (Conoco); and Vista Chemical Company (Vista). Ownership interests in NISCO are as follows: Citgo, 49.5 percent; Conoco, 36.1 percent; Vista, 13.4 percent; and GSU, 1.0 percent.

33. GSU is requesting recognition of $185,094,913 in fuel costs associated with the NISCO project during the reconciliation period. This amount is comprised of $77,448,704 in avoided fuel costs and an additional $107,646,209 in fuel costs above GSU's avoided cost.

34. NISCO is a qualifying facility (QF) under the Public Utility Regulatory Policies Act of 1978 (PURPA). NISCO has entered into a buy/sell power arrangement with GSU for the power it generates at Nelson 1 and 2 and the power the Industrial Participants receive at their various delivery points associated with retail electric service with GSU. The Industrial Participants pay for power sold to them by GSU at approximately the then-current Louisiana large industrial service (LIS) rate. This rate is called the 'IPS rate.'

***96** 35. GSU pays NISCO for purchased power based on the IPS rate less a margin. During the initial gas operations phase, the margin is 5 mils. During the petroleum coke phase, the margin will be 14 percent of the difference between the IPS rate and NISCO's cost of production.

36. In late 1986, GSU filed an application under PURA § 63 for approval of its transfer of ownership of Nelson 1 and 2 to NISCO and for approval of its proposed regulatory treatment of the revenues and expenses associated with the NISCO project. *Application of Gulf States Utilities Company for Approval of a Joint Venture Cogeneration Project and Treatment of Revenues*, Docket No. 7147, 14 P.U.C. BULL. 50 (March 21, 1988).

37. In Docket No. 7147, the Commission found that the transfer of Nelson Units 1 and 2 to NISCO was in the public interest under PURA § 63 as long as the purchased power payments to the venture did not exceed GSU's avoided costs. Moreover, the Commission limited GSU's recovery of the NISCO purchased power payments from ratepayers in future rate proceedings to an amount not exceeding GSU's avoided costs.

38. On appeal, the Third Court of Appeals reversed and remanded the Commission's decision. The Texas Supreme Court subsequently affirmed the judgment of the Court of Appeals. *Public Utility Commission v. Gulf States Utilities Company*, 809 S.W.2d 201, 212 (Tex. 1991); *Gulf States Utilities Company v. Public Utility Commission*, 784 S.W.2d 519, 533 (Tex. App.-Austin 1990, writ granted).

39. The Texas Supreme Court ordered the Commission to allow GSU to recover purchased power payments to NISCO in excess of avoided costs in future rate proceedings if GSU establishes, to the Commission's satisfaction, that the payments are reasonable and necessary expenses.

40. Under the Texas Supreme Court's test, GSU must show that: (1) absent the NISCO Venture, the industrial customers would have left its system because independent cogeneration was economically more attractive than remaining in the system; (2) that the contractual rates are necessary to make the NISCO Venture more attractive than independent cogeneration; and (3) that such rates are at the minimum level.

41. If GSU satisfies the elements of this three-part test, then the Commission will determine the amount of NISCO costs, if any, GSU's ratepayers should reasonably bear.

42. The allocation of the gain on the sale is not an issue in this docket, but is instead the subject of pending Docket No. 11776, *Application of Gulf States Utilities Company for Approval of a Joint Venture Cogeneration Project and Treatment of Revenues (Remand)* (pending).

43. GSU is purchasing electricity and load retention from NISCO.

44. GSU's payments to NISCO above avoided cost are base rate load retention payments which should be considered in the context of a base rate case.

45. The Commission has previously ordered the shareholders of the utility to bear the load retention costs. *Application of Gulf States Utilities Company for Approval of Experimental Rider to Schedules LPS and LIS*, Docket No. 7309, 13 P.U.C. BULL. 1629, 1683 (May 13, 1987); *Application of Central Power and Light Company For a Large Industrial Power Experimental Rider 16*, Docket No. 7596, 13 P.U.C. BULL. 858 (Sept. 25, 1987) (mem.). In GSU's last rate case, the Commission rejected GSU's request that Texas ratepayers pay non-jurisdictional load retention costs. Docket No. 8702, 17 P.U.C. BULL. at 849.

***97** 46. During the mid-1980s, GSU's industrial customers were concerned about the effect on rates of the inclusion of River Bend in GSU's rate base and the termination of certain long-term gas contracts.

47. GSU has lost 578 MW of load since 1984: 484 MW in its Louisiana jurisdiction and 94 MW in Texas.

48. Citgo's alternatives were to consider smaller generation projects using gas turbine or other gas-fired equipment, or to consider joining with other partners to pursue larger projects using the petroleum coke produced as a by-product at its refinery as a fuel. During the mid-1980s, Citgo and Conoco began discussions about the possibility of building a joint venture coke-fired generating plant on or near Citgo's refinery. Citgo also considered the installation of gas turbines.

49. In late 1984, Conoco informed GSU of its intent to pursue self-generation options.

50. Options available to Conoco were: (1) the construction of a stand-alone gas turbine project; (2) a potential joint venture petroleum coke facility with Vista; and (3) purchase of cogeneration facilities owned by PPG Industries and conversion of those facilities to coke-fired boilers. Conoco still intended to take backup power from GSU under these options.

51. GSU proposed an SUS incentive rate as an alternative to NISCO in 1986 after GSU and the Industrial Participants had begun the NISCO discussions.

52. Vista's options to NISCO included: (1) a multiple gas turbine project undertaken as a joint project among Citgo, Conoco, and Vista; (2) stand-alone gas-fired turbine generators; and (3) joint venture coke-fired projects not including GSU. Vista still intended to negotiate with GSU for standby power regardless of these options.

53. None of the Industrial Participants had approved any of the self-cogeneration options discussed and were not prepared to leave GSU's system to pursue one or more such options.

54. An incentive rate could have been structured to maintain, at least partially, some of the load on the system.

55. GSU failed to prove that the Industrial Participants would have left GSU's system absent the NISCO venture.

56. An incentive rate with a sufficient enough discount would have reduced the incentive to participate in NISCO sufficiently to overcome any long-term or short-term objections held by Conoco.

57. Conoco was indifferent to the precise price in the NISCO rate as long as the differential between the buy and sell prices was maintained.

58. The Louisiana Public Service Commission (LPSC) had required GSU's shareholders to bear the losses associated with incentive rates charged in Louisiana.

59. The total revenue reduction, for both Texas and Louisiana, associated with the SUS rates through December 1991 totals $34,231,056, which GSU's shareholders have absorbed.

60. If GSU had opted for incentive rates instead of forming NISCO, the opportunity for profit from the sale of Nelson Units 1 and 2 would have been forgone.

***98** 61. GSU has failed to prove that the NISCO contractual rates, as incorporated into the agreement, were necessary to make NISCO more attractive than cogeneration.

62. GSU did not offer any credible contemporaneous evidence of the NISCO rate negotiations which would have demonstrated that GSU held the line on the contractual rates.

63. GSU itself proposed the NISCO buy/sell formula that was ultimately incorporated into the agreement and the Industrial Participants agreed.

64. Although GSU considered the possibility of basing the NISCO buy/sell formula on its avoided cost, it never offered that option to the Industrial Participants.

65. A buy/sell formula based on avoided cost would have been much lower than the buy/sell formula actually incorporated into the NISCO agreement and would have resulted in the recognition of all NISCO costs as base rate revenue reductions in GSU's Louisiana jurisdiction.

66. Citgo would not have ruled out other pricing possibilities.

67. Depending upon when the calculation was done and whether the fixed asset payment was capitalized, the IRRs calculated for the NISCO project ranged from 25.7 to 31.1 percent on the low side and from 46 to 49 percent on the high side.

68. Expected IRRs for cogeneration alternatives ranged from approximately 20 percent to 36 percent.

69. The fact that the NISCO venture was expected to yield returns that exceeded the hurdle rate or the rate from alternative projects suggested that the final NISCO agreement was less favorable to the ratepayers than could have been achieved by effective negotiations.

70. Based on the average IPS rate of 4.4 cents per KWH during the reconciliation period, less the 0.5 cents per KWH variable service fee, the average cost per KWH purchased from NISCO by GSU was 3.9 cents per KWH.

71. GSU's avoided cost was 1.7 cents per KWH during the reconciliation period.

72. The net purchased power cost incurred by the Industrial Participants, excluding the purchase of surplus NISCO generation at GSU's avoided cost, was 1.5 cents per KWH, or 2.9 cents per KWH below the average IPS rate.

73. The actual cost of fuel used by NISCO is less than 0.5 cents per KWH.

74. GSU failed to prove that the NISCO contractual rates are at a minimum level.

75. None of the revenue received from NISCO is assigned to Texas; it is directly assigned to Louisiana.

76. The NISCO payments above avoided cost should not be borne by GSU's Texas ratepayers because those amounts are base rate load retention payments to retain load in Louisiana.

77. When fuel savings realized from not serving the Industrial Participants are netted out of the estimated $17 million in base rate revenues losses, the estimated cost of losing the three industrial customers during the first year totalled $10.9 million on a total company basis, of which $4.2 million constituted the Texas jurisdictional share. This compares with the annual Texas jurisdictional share of

$14.4 million annually above avoided cost that GSU is requesting to recover in this case.

***99** 78. The potential existed that Nelson Units 1 and 2 would have been removed from rate base regardless of NISCO.

79. In 1988, GSU had active excess reserves equal to 987 MW, as well as 443 MW of mothballed gas capacity. Currently, GSU estimates that it has 729 MW of active capacity and 405 MW of inactive capacity available for sale. Without the sale of the two Nelson units to NISCO, the Company's reserve margin would have approached 60 percent.

80. The NISCO contract provisions requiring unanimous consent include major changes in operations or policies related to the joint venture generating facilities; adoption or revisions of the annual operating and maintenance schedule of the joint venture generating units; contracting for major purchases, fuel, and limestone; and staffing of key personnel for the joint venture.

81. These unanimous consent provisions give GSU the ability to participate in the NISCO venture far in excess of its nominal one percent ownership interest.

82. The NISCO management committee is comprised of no more than three members from each NISCO participant, including GSU. The management committee has the exclusive authority to control, manage, and direct the business of the NISCO venture and to take all actions necessary to further the purpose of the NISCO agreement.

83. None of the GSU representatives on the management committee hold an elected position with the committee.

84. There are no officers or directors of GSU which are officers and/or directors of NISCO. GSU's representatives on the management committee are not officers or directors of GSU.

85. Each participant has the number of votes which is equal to the ownership interest of the participant. All actions of the management committee require a majority of at least 65 percent of the voting power except when a unanimous vote is required. Seventy-five percent of the participants are necessary for a quorum with GSU constituting 25 percent.

86. GSU has not invoked any of the unanimous consent provisions of the partnership agreement.

87. Nearly all of the significant management policy actions by the NISCO management committee require unanimous consent.

88. Because GSU's consent is required for actions requiring unanimous consent, GSU has the power to exercise substantial influence or control over the management and policies of NISCO.

89. Withholding consent in certain instances could be used by GSU or any of the Industrial Participants as leverage in negotiations or decisions regarding policy or management.

90. Costs for modifications to GSU's common facilities at the Nelson station are required to be discussed and approved by GSU and NISCO prior to commencing any expenditure provided that approval is not unreasonably withheld.

91. GSU is the buyer of last resort if an Industrial Participant withdraws from the NISCO venture provided that GSU is not required to acquire a greater than 50 percent interest in the project.

92. NISCO has the right to initiate negotiations with GSU for the purchase of Unit 3. GSU is free to enter into negotiations about Unit 3 with any third party. If such negotiations occurred, NISCO's option on Unit 3 would be suspended until the negotiations between GSU and the third party were either completed or dissolved.

***100** 93. NISCO has the power to exercise influence and control, directly and indirectly, over the management policies and actions of GSU through the unanimous consent provisions.

94. Dr. Hadaway's alternative analysis compared the net price GSU charged NISCO with the price GSU charged its SUS incentive rate customers rather than comparing the price NISCO charged GSU versus the price NISCO charged to other non-affiliate entities.

95. Dr. Hadaway used SUS rates as the relative comparison to NISCO's net cost because the SUS rates were the alternative load retention rates available at the time the NISCO decisions were made.

96. Because GSU does not make any other purchases of power which exceed its avoided cost, the price NISCO charges GSU far exceeds the price GSU would pay for purchased power from other sources.

97. GSU did not effectively rebut the proposition that the current NISCO price exceeds the price NISCO could charge on the open market.

98. GSU failed to present evidence proving: (1) that the expenses included in the NISCO payments do not include expenses which should be disallowed for ratemaking purposes; (2) that the allocated percentages of common facilities at the Nelson Station between GSU and NISCO are appropriate or reasonable; (3) that the costs incurred by NISCO and paid by GSU are reasonable; and (4) that the allocated amounts reasonably approximate the actual cost of service incurred.

99. The NISCO allocated costs are based on estimates.

100. Based upon a review of 1990 and 1991, GSU's payments to NISCO for power exceeded the cost of providing the service. In 1990, the NISCO costs were $49.9 million, or 20 percent lower than GSU's payments to NISCO. During 1991, the NISCO costs were $45.6 million, or 26 percent lower than GSU's payments to NISCO.

101. GSU's prudence analysis used 1985 information instead of information known or knowable to GSU in April 1988 when the NISCO agreement was consummated. It did not include any of the effects of the rate base inclusion of River Bend on GSU's rates which were known in 1988, but did include an understated IPS rate and overstated gas prices.

102. GSU's prudence analysis failed to consider the jurisdictional issue or the possibility that a portion of the Industrial Participants' load could have been maintained.

103. Dr. Hadaway's four scenarios compared customer costs with and without the NISCO venture; each used a 10 percent discount rate to bring all payments to present value status. In the first three scenarios, Dr. Hadaway used GSU's base case, high, and low marginal fuel cost estimates, respectively. The fourth scenario escalated the IPS base rate to demonstrate his contention that GSU's ratepayers were insulated from IPS base rate increases by the NISCO contract pricing provisions.

104. For his cogeneration option, Dr. Hadaway assumed that it would have taken 2.75 years for the Industrial Participants to construct their cogeneration facilities.

***101** 105. The Industrial Participants would remain on GSU's system during this construction period and pay the full standard tariff non-fuel revenue of $21.3 million per year. After the cogeneration facilities were constructed, Dr. Hadaway assumed the Industrial Participants paid stand-by fees and facility charges of $4.3 million per year.

106. Based on GSU's projected fuel year ending June 30, **1993**, the total cost of generated and purchased power estimated by GSU is $574,528,321, of which $32,008,369 is attributable to NISCO. The NISCO power costs are approximately $39.52/MWH compared to GSU's system average MWH power cost of approximately $19.25/MWH. The next highest system power cost excluding NISCO is Willow Glen 2 power at approximately $22.55/MWH. The purchased power cost from other cogenerators is $16.34/MWH.

107. In addition to reviewing the costs incurred if the Industrial Participants left the system for cogeneration and the costs incurred under the NISCO venture, Beaumont witness Mr. Lawton analyzed GSU's option to sell Nelson Units 1 and 2 to the three industrial customers on a non-participating basis. When the sell-but-not participate option was considered, Mr. Lawton calculated that NISCO resulted in a $27,855,869 detriment to ratepayers.

108. In the calculation of computed fuel savings under the cogeneration option, Mr. Lawton used 1,517,828 MWH for the system load lost if the three industrial customers left the system as compared to Dr. Hadaway's figure of 1,411,580 MWH.

109. The actual sales level of the industrial customers was 1,517,828 MWH.

110. Mr. Lawton assumed a 100 percent capacity factor rather than Dr. Hadaway's 93 percent capacity factor because the higher capacity factor served as a proxy for calculating the revenue received by GSU for stand-by power in the event the cogeneration facility shut down. Dr. Hadaway assumed a 93 percent capacity factor but did not include any revenue that GSU would receive for additional sales of power to the industrial customers.

111. Mr. Lawton's adjustment for MWH to account for revenues received for stand-by service is not unreasonable although expecting a 100 percent capacity factor is unrealistic.

112. Mr. Lawton added $3 million per year to the estimated cogeneration stream to reflect GSU's assumptions that management services provided to the NISCO project could generate that revenue under the sell-but-not-participate option.

113. GSU estimated the value of its management services to the industrial customers under the sell-but-not-participate option as $3 to $8 million annually.

114. It is reasonable to account for the value of the management services under the sell-but-not-participate option as Mr. Lawton did.

115. Mr. Lawton deducted $4 million per year for the first ten years from NISCO's contribution to system fixed costs to account for GSU's receipt of the purchase payments from the industrial customers under the sell-but-not-participate option.

***102** 116. It is reasonable to subtract $4 million per year from the NISCO contribution to fixed cost as proposed by Mr. Lawton because his subtraction is based on GSU's expectation that it would have to return the gain on the sale to ratepayers over a five-to ten-year period.

117. GSU failed to prove that it prudently incurred the NISCO costs above its avoided cost.

118. No other cogenerators are similarly situated with the Industrial Participants.

119. During the reconciliation period, GSU's total off-system sales equalled $19,214,350. Of this amount, $14,948,275 was classified by GSU as reconcilable fuel revenue which reduced GSU's reconcilable fuel costs. The remaining $4,266,075, or adder, was classified as non-reconcilable non-fuel revenue.

120. The effect of classifying the adder as non-reconcilable is that the adder does not reduce GSU's reconcilable fuel balance and is therefore retained by the shareholders.

121. In GSU's last rate case, Docket No. 8702, the issue of whether to treat GSU's off-system sales as non-reconcilable was not contested, not argued in briefs, or presented to the Commission in oral argument.

122. Because GSU had removed the off-system sales adders from both its reconcilable fuel expense and its non-reconcilable base rate revenue requirement in Docket No. 8702, any classification of the

adders in this case as reconcilable would not be a retroactive change.

123. In Docket No. 9945, EPE's last rate case, the Commission allowed EPE to retain the profits from its off-system sale to La Comision Federal de Electricidad de Mexico (CFE) because EPE's Palo Verde Unit 3 was not included in rate base, and because EPE's financial condition was found to be extremely poor. *Application of El Paso Electric Company for Authority to Change Rates*, Docket No. 9945, Findings of Fact Nos. 212A, 216, 217, 218, 18 P.U.C. BULL. 9, 578-579 (February 6, 1992).

124. In Docket No. 8425, HL&P's off-system sales profits occurring during its reconciliation period were reconciled. *Application of Houston Lighting and Power for Authority to Change Rates*, Docket No. 8425, Finding of Fact No. 97, 16 P.U.C. BULL. 2199, 2721 (June 20, 1990).

125. In Docket No. 9300, TU Electric was required to include its test year off-system sales profit as miscellaneous revenue in calculating its revenue requirement. *Application of Texas Utilities Electric Company for Authority to Change Rates*, Docket No. 9300, Finding of Fact No. 230, 17 P.U.C. BULL. 2057, 2872 (Sept. 21, 1991).

126. GSU's off-system sales are made possible by plants that the ratepayers have paid for or are paying for now.

127. There is no credible evidence demonstrating that an incentive is necessary to encourage GSU to engage in off-system sales which have already taken place during the reconciliation period.

128. There is no credible evidence of the impact of the proposed allocation on GSU's financial strength.

129. Off-system sales are not a significant portion of GSU's business.

***103** 130. There were no dividends paid to GSU's shareholders during the reconciliation period, but there is no credible evidence as to if or how that omission has affected GSU's financial condition.

131. There is no credible evidence regarding ratepayer burdens resulting from GSU's off-system sales.

132. GSU's current base rates are based upon the test year ending in September 1988. During that test year, GSU's off-system sales totalled slightly over 1.2 million MWH which is approximately four times the current annual level of off-system sales. Incremental O&M was not removed from the test year O&M amount. Therefore, GSU's test year O&M included approximately $720,000 per year of incremental O&M for off-system sales. This is approximately $540,000 per year more than the current level.

133. GSU's current base rates include more than sufficient incremental O&M expense to cover the off-system sales which occurred during the reconciliation period.

134. There is no credible evidentiary basis for concluding that a portion of the reconciliation period off-system sales adders should be allocated to the shareholders.

135. One hundred percent of the off-system sales adders from the reconciliation period, or $4,226,075, should be treated as reconcilable in this case.

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 fuel amortization, spent fuel and interest expense.

137. River Bend Refueling Outage 2 (RFO-2) began on March 15, 1989, and ended on June 8, 1989. RFO-2 was initially scheduled to last for 60 days but actually lasted 85 days.

138. During RFO-2, the critical path schedule of the outage was delayed by work done on the Division

I diesel generator.

139. The contractor selected by GSU to perform the diesel work for GSU during RFO-2, Cooper Industries, failed to complete its work on schedule, resulting in a delay of the critical path schedule and an extension of RFO-2. There were approximately 17 days of duration variation in the Division I diesel inspection, 11 of which were a slip in the critical path schedule.

140. GSU experienced delays in Cooper's work prior to the beginning of RFO-2, and expended a considerable amount of time and effort to improve Cooper's performance.

141. The Cooper site management and planning efforts started late and caused a 'never on time' ripple effect throughout most of the outage.

142. GSU's RFO-2 Outage History Report attributed the Division I diesel generator inspection delays to the contractor's lack of familiarity with GSU procedures.

143. Work was scheduled to start on the Division II diesel generator immediately after the completion of the Division I Emergency Core Cooling System (ECCS) test. The Division II diesel generator work did not start until April 16, 1989, however, despite the fact that the ECCS test was completed on April 14, 1989.

***104** 144. The Division II ECCS test which was scheduled to be completed on April 23, 1989, was actually completed on May 12, 1989, 19 days later than scheduled.

145. River Bend has a safety tagging system to prevent the operation of plant equipment when such could cause personal injury or equipment damage. This system requires maintenance personnel to obtain a clearance to make repairs, design changes, and perform routine maintenance on plant equipment. Repeated violations of the safety tagging procedure were experienced during the first month of RFO-2.

146. On April 13, 1989, GSU issued a stop work directive which halted work by Cooper until its personnel could be retrained and an assessment of Cooper's work could be performed.

147. The stop work directive was lifted on April 14, 1989.

148. A lack of adequate training in GSU's procedures was responsible for the tagging violations.

149. NRC Inspection Report No. 89-11 found that GSU failed to take adequate corrective actions to prevent new violations of its tagging system based on the conclusion that the corrective actions taken by GSU during the first month of RFO-2 failed to determine the extent to which tagging program violations existed.

150. Due to poor performance, GSU removed Cooper's original project manager from the site during RFO-2.

151. The outage history report for RFO-2 indicates that GSU had to repair an intake manifold crack and install intake manifold braces. However, the schedule variance for RFO-2 lists Cooper's problems as the reason for the delay, not the manifold bolt repairs.

152. The 11-day delay in the critical path resulted from imprudence. The resulting increase in fuel costs of $1,584,012 on a total company basis should be disallowed.

153. After the Division I diesel generator work was finished on April 14, 1989, the reactor water cleanup system (RWCU) work was extended from 12 to 35 days. Consequently, this effort became the critical path and remained so until May 14, 1989.

154. The work which extended the RWCU outage involved a series of valve repairs and retests. Forty-eight of 208 valves tested failed the Local Leak Rate Test (LLRT).

155. Anchor Darling Valve Company (Anchor Darling) was the contractor for the valve repairs.

156. GSU issued a stop work directive on April 13, 1989 until Anchor Darling's personnel could be retained and an assessment made of Anchor Darling's work. GSU had to repair and retest a number of valves previously repaired by Anchor Darling, and eventually transferred the valve repair work to Stone & Webster in late April and early May 1989.

157. The valves at issue could not be worked on 24 hours a day. Consequently, putting more personnel on the valve job would not have solved the problem because physical size limitations restricted the number of people who could work in that area.

158. The RWCU work could not begin until the Division I ECCS test was completed. The Division I ECCS test was finished on April 14, 1989, the same date that the stop work directive was removed. The LLRT for the RWCU valves began on April 14, 1989, the first date that such work could begin.

***105** 159. GSU was able to rework and retest the valves in time to prevent further delay in the critical path of RFO-2.

160. On May 29, 1989, near the scheduled end of the second refueling outage, the B preferred transformer was energized following routine maintenance, exploded, and caught on fire, resulting in a forced outage until the installation of a replacement transformer. The forced outage to replace the B preferred transformer began at the end of the second refueling outage on June 8, 1989, and ended on June 24, 1989. It effectively resulted in a 16-day extension of the second refueling outage.

161. Prior problems with the A preferred transformer should have alerted GSU to the potential problem with the B preferred transformer because the A and B preferred transformers were capable of serving the same load.

162. The A preferred transformer initially failed on June 14, 1985. The transformer apparently experienced a number of low-side faults which probably caused progressive winding distortion that finally resulted in the failure.

163. Early in RFO-2, oil samples taken from the A preferred transformer indicated a problem with that transformer. The presence of dissolved combustion product gases in the oil sample indicates an internal arcing in the transformer.

164. After GSU discovered the dissolved gases in the A preferred transformer, GSU conducted a Doble test. The Doble test performed on the A preferred transformer showed that high excitation currents existed and that the transformer had deteriorated. The cause of this deterioration was most likely low-side or secondary faults from the auxiliary boiler.

165. The failure of the A preferred transformer was due to the inability of the transformer to handle the repeated through faults to which it had been subjected.

166. Prior to the May 29, 1989 event, the B preferred transformer energized and tripped due to secondary cable faults on May 2, 1989, and May 23, 1989. These secondary cable faults were low-side or through faults.

167. GSU performed a Doble test on the B preferred transformer on May 9, 1989, following the trip on May 2, 1989.

168. Oil samples were again taken following the May 23, 1989 trip to determine the presence of gases, but the results were once again negative. GSU decided that an additional Doble test was not warranted because the previous Doble test performed on May 9, 1989 was normal as were the oil sample results.

169. United Engineers & Constructors, Inc. (UEC) prepared an analysis of the B preferred transformer

failure for GSU.

170. According to UEC, the B preferred transformer suffered mechanical damage which was caused by excessive axial short circuit forces.

171. The auxiliary boiler had been fed by the A and B preferred transformers. The relatively frequent faults in the auxiliary boiler contributed to the transformer failures.

172. GSU should have known that the prior problems with the A preferred transformer put the B preferred transformer at risk.

***106** 173. The 16-day delay for the B preferred transformer fire was the result of imprudence. The resulting $2,245,911 in fuel costs should be disallowed.

174. River Bend Refueling Outage 3 (RFO-3) began on September 29, 1990, and ended on December 4, 1990. The outage was scheduled to last for 58 days but actually lasted 66 days.

175. A six-day delay of the outage was due to the synchronization of the Division II diesel generator out-of-phase to the grid.

176. The function of the Division II diesel generator is to provide power to the Division II equipment when off-site power is lost. During the outage, either the Division I or the Division II diesel generator must be operable.

177. On October 21, 1990, the Division II diesel generator was undergoing post-maintenance testing. During this testing, the generator was scheduled to be synchronized to the plant's electrical grid to verify that its load carrying capability had not been degraded. The process of synchronizing the diesel generator to the grid was performed by a Unit Operator, who manually closed the diesel generator's output breaker when the diesel generator and the grid voltages were in phase. In synchronizing the Division II diesel generator, however, the Unit Operator mistakenly closed the diesel generator output breaker with the generator voltage out-of-phase with that of the grid.

178. River Bend's Independent Safety Engineering Group (ISEG) prepared an analysis of the out-of-phase synchronization of the Division II diesel generator.

179. According to ISEG, the event was solely due to operator inattentiveness and failure to follow procedure. Other factors such as inadequate training, experience, and procedures did not contribute to the incident.

180. According to ISEG's analysis, if synchronization check devices had been installed at River Bend, the operator could not have closed the diesel generator output breaker at the incorrect moment.

181. In August 1985, ISEG concluded that it was possible to synchronize the diesel generator and the grid out-of-phase.

182. Synchronization occurs at least 36 times per year. ISEG recommended in 1985 that a synchronization check device be installed in the circuit breaker control circuits to prevent the breaker from connecting two out-of-phase voltages.

183. ISEG's Special Analysis report (SA 90-011) indicated that the recommendation made by ISEG in 1985 was made in the form of an Engineering Evaluation and Request (EEAR). An EEAR requests the Engineering Department to review a recommendation to determine whether it should be implemented.

184. The EEAR was not presented to the Work Scope Committee because Design Engineering characterized the requested EEAR as a betterment.

185. The failure to perform the synchronization of the Division II diesel generator to the grid was an

isolated error which resulted in a delay to the third refueling outage.

186. It was not imprudent for GSU to choose not to evaluate the installation of synchronization check devices based on ISEG's earlier analysis because: (1) the devices are not required for the safe operation of the plant; (2) the probability of an out-of-phase event is very low; (3) the operator must perform the function properly regardless of whether a synchronization check device is installed; and (4) training, experience or procedures did not contribute to the event.

***107** 187. In November 1990, a crack about one and one-half inches long was discovered in the welded connection between the Division II diesel turbo-charger exhaust and the intercooler.

188. Drawings of the weld were reviewed during the diesel's design and installation and were found to be acceptable. The vendor installed the shop weld according to those drawings. However, the gap between the pieces joined by the weld was too wide for the size of the weld specified. Once the weld was made, the gap was hidden from view.

189. A quality assurance program cannot guarantee that there will be no defects.

190. The one-day delay attributable to the diesel generator exhaust water jacket repair was not the result of imprudence.

191. On October 20, 1990, a fire occurred in the insulation around the exhaust expansion joint on the Division II diesel generator.

192. The design of the diesel exhaust system allowed a portion of the exhaust gas to blow by the expansion joint to eliminate friction and reduce loading on the turbo-charger housing.

193. The diesel had been running unloaded for approximately two and one-half hours prior to the fire. Running the diesel in such an unloaded condition can result in the presence of more unburned fuel in the exhaust gas than is normally present when the diesel is run under load.

194. GSU's Condition Report CR #90-0963 stated that the exhaust blow-by feature was not considered in the selection of jacketing materials.

195. Disallowance for the lost generation associated with approximately two days is appropriate. The fire was a direct cause of a design change, the consequences of which GSU imprudently failed to consider upon its implementation.

196. River Bend was automatically shut down on February 20, 1989. At the time, River Bend was in start-up from a previous plant outage. During the start-up, a decrease in reactor pressure caused by the opening of large steam line drain valves, without the compensation of in service turbine bypass valves, led to an automatic shutdown or scram of the reactor.

197. Main steam line drains are used to remove dense steam from the main steam line during plant operations. The valves isolating the drains are usually open during plant operation and closed during a shut down. During a reactor startup, the valves are sequentially opened. This process is controlled by General Operating Procedure GOP-001.

198. Scram 89-01 was the fourth scram at River Bend to occur under similar circumstances during a reactor start-up.

199. The ISEG report stated that keeping the turbine bypass valves in service during main steam line drain valve manipulations was one of the corrective actions adopted following Scram 86-SU-18 in January 1986. The Revision 6 of GOP-001 following Scram 86-SU-18 added the following cautionary note: If performing a Hot Startup, ensure adequate steam bypass capacity prior to opening drains which could increase steam flow.

200. When Revision 7 of GOP-001 was issued in 1987, this cautionary note was revised in a manner

that did not require that the turbine bypass valves be in service during steam line drain valve operations.

***108** 201. The deletion of instructions from GOP-001 Revision No. 7 caused the reactor pressure transient which resulted in Scram 89-01. Had GOP-001 not been improperly and imprudently revised, the scram and resulting outage could have been prevented.

202. The additional fuel costs of $153,489 resulting from the forced outage of 38 hours, 55 minutes should be disallowed.

203. On June 24, 1989 and June 29, 1989, River Bend was taken out of service to repair Electro-Hydraulic Control (EHC) oil leaks on the No. 2 and No. 3 turbine control valves.

204. Use of incorrect o-ring seals in the electro-hydraulic system caused the oil leaks.

205. The Ultra-seal o-ring cannot be satisfactorily replaced with a standard o-ring. The oil leaks were due to the failure of standard o-rings where proper Ultra-seal #4 o-rings were required.

206. GE craft personnel and supervisors who worked on the turbine control valves during the refueling outage should have recognized that the Parker-Hamifin fittings required a non-standard o-ring and should have researched the proper documentation to verify the correct parts.

207. The failure to apply the proper Ultra-seal o-ring could have been avoided had reference to the appropriate cite documentation been made.

208. Following the June 29, 1989 shutdown, GSU reviewed and evaluated all gaskets and o-rings used in the turbine control valves during 1989. This review found that of six additional connections in the remaining two turbine control valves, three connections had the required Ultra-seal o-rings and three had the incorrect standard o-rings.

209. The failure to use correct o-rings was imprudent. The resulting increase in fuel cost of $400,330 on a total company basis should be disallowed.

210. On December 12, 1990, a reactor scram occurred during performance of the weekly turbine overspeed operability test.

211. The root cause of this event was an electro-hydraulic trip system pressure transient. As air is trapped in the system and compressed, a large drop in the electro-hydrolic trip system pressure occurs, allowing the disk dump valve of the other turbine steam valves to release.

212. To prevent reoccurrence of this event, GSU has installed orifices in the electro-hydraulic trip system hydraulic fluid supply lines in all the turbine steam valves.

213. GE had identified corrective action for differently designed valves approximately eight years earlier.

214. The shutoff valves utilized at River Bend are of an older GE design.

215. GE's corporate position was that installation of orifices was not required at River Bend because air entrapment was not a problem with the valves at River Bend.

216. The outage that occurred during the turbine testing on December 12, 1990 was not the result of imprudence. GSU pursued reasonable corrective action based on the information that was available to it at the time.

217. High temperature in the steam tunnels at River Bend reduced the available power to 590 MW.

***109** 218. The root cause of the high temperature was personnel error.

219. GSU changed the start-up procedure to require a check of the damper position by operations personnel after everyone else completed work or inspection in the steam tunnel. High temperature in the steam tunnels was not the result of imprudence by GSU.

220. Feedwater Heater High Level Dump Valve Short Cycling is a catchall derating event for a group of valves that have been leaking during the operating cycle.

221. The heat rate at the beginning of a cycle will generally be better than at the end of a cycle during refueling outages. Some losses are judged to be non-recoverable because of the expense it would take to recover them. Most of the components are located in high radiation fields and cannot be worked on during plant operation.

222. These are normal losses which occur over the operating cycle of the plant. The record indicates GSU took reasonably prudent steps to reduce or eliminate the losses.

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.

224. GSU records nuclear interest payments even when River Bend is not operating.

225. The nuclear fuel interest costs are incurred whether the plant generates power or not. They must be included in the two calculations: (1) the cost incurred during an imprudent nuclear outage and (2) the postulated cost that would have occurred had there been no outage. The end result of this double inclusion is that nuclear fuel interest components drops out of the calculation altogether.

226. If the nuclear fuel interest costs are included only in the postulated cost of nuclear generation when there is no outage, as GSU proposed in its calculation, the net effect is to allow GSU to collect those interest expenses twice.

227. In November 1988, GSU's capacity factor for Big Cajun II, Unit 3 was approximately 40 percent.

228. The fuel cost used by GSU to dispatch its share of the Big Cajun unit was $1.7646/MMBtu, which was based on the estimated cost supplied by Cajun Electric for 1988 coal purchases.

229. The October 1988 funding statement provided to GSU by Cajun Electric forecasted a price of $1.4829/MMBtu. This forecasted price included a short-payment by Cajun Electric. Cajun Electric lost its litigation with Triton and was required to make up the short-payment.

230. The revised November 1988 funding statement showed a fuel price estimate for the month of $1.7235/MMBtu, unadjusted for coal degradation.

231. Around the 20th of each month, GSU begins to determine its dispatch cost for the following month. Meanwhile, Cajun Electric receives the invoices from the coal supplier and transporters and then forwards them to GSU. The invoices for November 1988 coal supply and transportation were received by Cajun Electric in late October 1988.

110 232. Normally a unit should be dispatched using incremental heat rate data.

233. It is not possible to use incremental heat rate data to dispatch jointly owned units where the joint owners do not always take energy in proportion to their capacity ownership.

234. Both Cajun Electric and GSU are entitled to independently dispatch or schedule their ownership share of Big Cajun II, Unit 3. Only if both utilities take the output of the unit in direct proportion to their ownership share at all times will both utilities receive equal benefits from incremental heat rates.

235. If GSU increased its output from the Big Cajun unit based upon the incremental heat rate curve

and Cajun Electric then reduced its output, the expected benefits from increasing GSU's output would not materialize.

236. Because it does not control the output of the unit and cannot predict how Cajun Electric will use the unit, GSU reasonably schedules generation from Big Cajun II, Unit 3 based on average heat rate data.

237. GSU reasonably dispatched its share of the Cajun unit in November 1988.

238. During December 1989, the first half of the month was mild but the third week was very cold. GSU had to burn oil and contract for off-system power subject to take requirements to offset curtailments of natural gas. GSU also burned long-term gas which caused it to exceed contract minimums.

239. GSU implemented the same cold-weather precautions for February 1990, which included contracting for firm supplies of short-term gas to supplement its long-term gas. February 1990's weather, however, turned out to mild in comparison to December 1989. In order to satisfy the minimum contract requirements under the long-term and short-term firm contracts, GSU had to decrease its discretionary supplies, including use of Big Cajun II, Unit 3.

240. GSU reasonably dispatched its share of the Cajun unit in December 1989 and February 1990.

241. Peaking service occurs when a unit may be taken off-line on a daily basis or over a weekend. During periods of low system load, the generating units in service must operate at lower loads, resulting in higher heat rates. If one of the units can be taken off-line instead of operated at a low load, then the load on the other units may be increased with a corresponding improvement in the system heat rate.

242. GSU's system dispatch operators would not start Sabine 5 for 72 hours after it was taken off-line, which effectively precluded Sabine 5 from being used as a peaking facility.

243. Sabine 5 was designed for peaking service and has a design turbine heat rate consistent with peaking service; its turbine, however, was not purchased with peaking modifications because GSU expected to operate the unit in a load-following mode.

244. Any potential fuel savings from operating Sabine 5 in peaking mode would be outweighed by the additional costs associated with operating it as a peaking unit.

245. Peaking service increases the stress and wear on the steam turbine components, resulting in increased maintenance and unit heat rate, and decreased reliability and life of the unit.

***111** 246. Operating Sabine 5 in the peaking mode will not result in net fuel savings. GSU reasonably utilized this unit during the reconciliation period.

247. In April 1989, Cajun Electric and GSU entered into an agreement which permitted either party to purchase energy from the other party's ownership interest in Big Cajun II, Unit 3 at $3.50/MWH, with the purchasing party responsible for supplying the fuel. During the reconciliation period, GSU sold 23,711 MWH to Cajun Electric under this agreement for $82,989, while it purchased 1,225 MWH from Cajun Electric for $4,288.

248. GSU classified the $4,288 paid to Cajun Electric as a positive reconcilable fuel expense, but classified the $82,989 payment received from Cajun Electric as non-reconcilable.

249. There is no credible evidentiary basis for treating GSU's payment to Cajun Electric as reconcilable but not so treating the receipt from Cajun Electric.

250. State and local gross receipts taxes and fees, the PUC assessment, and uncollectible expense are all a function of the amount of kWh sold.

251. The revenue-related taxes and fees are related to the reconcilable fuel revenue, but they are also base rate items set by the Commission in a rate case.

252. The revenue-related taxes and fees associated with the overrecovery should not be disallowed in this case.

253. The Commission considered whether to adjust revenue-related taxes and fees in Docket No. 9300 and declined to do so. Docket No. 9300, 17 P.U.C. BULL. at 2619-2620, 2683 (Finding of Fact No. 392), 2729, 2825.

254. Starting in June 1991, the fuel expense related to certain of GSU's incentive rates was subtracted from GSU's total reconcilable fuel and purchased power expense before these expenses were allocated to the Texas jurisdiction and the over/underrecovery calculation was made. In addition, GSU removed the Texas incremental KWH sales from total Texas retail sales, and removed the total incremental KWH sales from the total system KWH sales.

255. Customers paying the incentive rates are not charged pursuant to the fixed fuel factor; rather, they are charged the incremental cost of fuel, whatever that cost happens to be when the customer uses electricity. To include the incremental expense and associated sales would result in both non-fixed fuel factor customers and fixed fuel factor customers being allocated an expense based on a combined incremental and system average cost.

256. Whether ratepayers are harmed by the exclusion or inclusion of incentive rate fuel expense depends upon whether incremental cost is less than or greater than system average cost.

257. Because incremental cost was less than system average cost during the reconciliation period, inclusion of incremental cost would decrease the reconcilable fuel expense.

258. It is reasonable to exclude incentive rate fuel expense from the reconcilable fuel balance.

259. Two interest rates are applicable to the refund or surcharge calculation for the reconciliation period in this case: (1) 11.48 percent, approved in Docket No. 7195, which is applicable to all interest calculations from September 1988 through February 1991; and (2) 11.94 percent, approved in Docket No. 8702, which is applicable to all interest calculations from March 1991 through September 1991.

***112** 260. GSU used the simple interest methodology to calculate the interest on its alleged underrecovery balance for this case.

261. GSU has been accruing simple interest on the deferred fuel balance during the reconciliation period.

262. Provisions in the substantive rules which require annual compounding of interest involve lower interest rates tied to shorter-term investments.

263. The Commission recently declined to adopt compound interest in Docket No. 9300.

264. It is reasonable to use the simple interest calculation in this case as recommended by GSU and the General Counsel.

265. P.U.C. SUBST. R. 23.23(b)(2)(G)(v) requires a one-time bill credit for implementing refunds unless it can be shown that the short time frame would be an incentive to use electricity excessively.

266. In GSU's last two rate cases, the Commission made specific findings regarding GSU's financial condition which supported approval of a longer time period than allowed by the substantive rule for accomplishing the refunds. Application of Gulf States Utilities Company for Authority to Change Rates, Docket No. 7195, 14 P.U.C. BULL. 1943, 2417 (Finding of Fact No. 240) (May 16, 1988); Docket No.

8702, 17 P.U.C. BULL. at 1022, (Finding of Fact No. 56) (May 2, 1991).

267. GSU did not present evidence on whether a longer time period for refunds was reasonable.

268. GSU failed to show good cause to deviate from P.U.C. SUBST. R. 23.23(b)(2)(G)(v) which requires a one-time bill credit for refunds.

269. GSU's proposed fuel year is July 1, 1992, through June 30, **1993**, while the General Counsel proposed a **1993** fuel year.

270. GSU used PROMOD, a production cost simulation model, for its fuel factor calculations while the General Counsel used a spreadsheet analysis.

271. GSU did not rebut the **1993** fuel year proposed by the General Counsel.

272. PROMOD is generally more accurate and sophisticated than a spreadsheet analysis.

273. There are contested assumptions underlying the PROMOD modeling which are not in evidence.

274. The General Counsel's proposed fuel year is based on information projected for the time that the fuel factor will be in effect, and, as modified by ALJ, is reasonable.

275. Except as modified by the ALJ, the General Counsel's proposed fuel year is reasonable and should be adopted.

276. In August 1991, GSU and Sabine Gas Transmission Company (SGT) entered into the 1991 Amended and Restated Gas Transportation Agreement (the Transportation Agreement) which requires SGT to provide transportation and swing service to GSU in return for a transportation fee paid by GSU.

277. GSU's payments to SGT only affect the fixed fuel factor calculation in this proceeding because the Sabine Spindletop project was not in operation during the reconciliation period.

278. The Transportation Agreement provides for delivery by GSU of gas to the Texas Sabine Pipeline System and re-delivery to GSU on a delayed basis. GSU pays SGT a monthly transportation fee per MMBtu of gas delivered to SGT's pipeline system plus a charge for electricity to operate the storage facility. SGT credits a portion of the transportation fee received from GSU to the 'Non-Credit Payment;' and the remainder of the fee is credited to the 'Credit Payment.'

***113** 279. The Non-Credit Payment is an amount per MMBtu subject to adjustment and the Credit Payment is the remainder of the transportation fee in excess of the Non-Credit Payment. The Credit Payment is applied by SGT against the 'Payoff Amount' which consists of SGT's installation costs for the Spindletop facility including interest. The Payoff Amount is adjusted each month by the Credit Payment and accrued interest. When the Payoff Amount equals zero, the Credit Payment portion of the transportation fee is eliminated.

280. GSU is also required under the Transportation Agreement to deliver a minimum quantity of gas to SGT or pay an Amortization Fee based on the minimum quantity not delivered. This minimum quantity payment is $9,000,000. When the Payoff Amount reaches zero, the minimum quantity obligation is also eliminated.

281. Under the 1991 Amended and Restated Optional Purchase and Amortization Agreement (the Optional Purchase and Amortization Agreement), GSU has the option to purchase the facilities from SGT for a sum equal to the Payoff Amount provided that the purchase price is not less than one dollar.

282. The current market value of the facilities is approximately $40,000,000.

283. Under GSU's worst case scenario, after adjusting for the minimum fuel burn at Sabine Station, expenses will average approximately $11,258,000 per year over the first seven years, but will be offset by an average annual projected savings over those seven years of approximately $11,568,000. At the end of the seventh year, GSU projects a cumulative net present value savings of $403,000 under the worst case scenario. Under GSU's expected case scenario, GSU projects a cumulative net present value savings of $48,879,000 at the end of the seventh year.

284. If the payments to SGT are recovered through the fixed fuel factor in this case, GSU has agreed to credit revenues received from the existing facility to off-set the reconcilable fuel expense.

285. In Docket No. 8425, the Commission included costs from HL&P's leased North Dayton gas storage facility in HL&P's known and reasonably predictable fuel costs.

286. The Commission found that the storage capability provided by the North Dayton storage facility was a central feature of HL&P's gas acquisition strategy. If HL&P had not separately paid for gas storage then any gas storage services purchased by HL&P would have been provided by gas suppliers and charged to HL&P through increased gas prices. This increase in gas prices would have been recovered through the fuel factor.

287. The Commission determined in Docket No. 8425 that known or reasonably predictable fuel costs may include those costs that show that the Company has planned and operated its facility and fuel-procurement programs prudently, with the objective of providing reliable power at the lowest reasonable total cost.

288. GSU's payments to SGT are reconcilable fuel costs based on the Commission's application of the Fuel Rule in Docket Nos. 8425 and 9300.

***114** 289. GSU does not have legal title to the Sabine Spindletop facility or the land upon which it is located.

290. GSU has significant authority to direct the construction, design and operation of the facilities by SGT.

291. GSU has the right to approve the budget, engineering designs, bid specifications, selection of the contractor, equipment specifications and terms of agreements between SGT and third parties regarding storage.

292. The revenue derived from third party storage is credited to GSU.

293. GSU is the manager of the construction project, operates and maintains the equipment on SGT's pipeline and provides contract administrative services to SGT.

294. SGT is precluded from expanding the facilities without GSU approval so that GSU can prevent SGT from profiting from the initial capital intensive nature of constructing the storage facility by adding additional storage after GSU's storage needs are met.

295. GSU's control over the construction and equipment ensures that the facility is constructed in the proper manner in the event GSU exercises its option on the facility.

296. GSU maintains control over third-party use of the storage facility to prevent SGT from retaining any revenue received from third-parties. Revenue received from third-party use of the facility will reduce the Payoff Amount and, ultimately, the transportation fee.

297. GSU's control over the design, construction and operation of the Sabine Spindletop facilities does not require GSU to seek rate base treatment for its payments to SGT.

298. The terms Credit Payment and Non-Credit Payment are contractual terms used to define SGT's use of the proceeds received from GSU.

299. GSU pays SGT a fee for transportation and swing service, and SGT portions out the proceeds between a Credit Payment and a Non-Credit Payment.

300. All gas companies use a portion of the fee they receive to defray capital costs.

301. It is not unusual to have a minimum take-or-pay obligation in a contract.

302. The fact that the arrangement allows SGT to pay off its capital costs in constructing the project and includes a minimum annual payment does not prevent GSU from seeking to include the SGT payments in the fuel factor.

303. According to Financial Accounting Standards Board (FASB) Statement No. 13, a capital lease is one that, from the standpoint of the lessee, transfers to the lessee substantially all of the benefits and risks incidental to ownership of the leased property. A capital lease is accounted for by the lessee as the acquisition of an asset and the incurring of a liability.

304. GSU categorizes the Spindletop gas storage facility as a capital lease.

305. GSU has never requested that any of its other capital leases, including its nuclear fuel lease, be included in GSU's rate base.

306. Because GSU currently has no investment in the facility and no requirement to invest or to exercise the option, future rate base treatment is uncertain.

***115** 307. Merely because GSU accounts for the Sabine Spindletop facility as a capital lease does not require GSU to seek rate base treatment of the costs if the costs otherwise are includible under the Commission's application of the Fuel Rule.

308. If GSU had chosen to own and operate the storage facility itself, then GSU's investment in the facility would have been included in rate base and return would have been included in base rates.

309. GSU did not have the means to build the facility itself due to budgetary constraints.

310. Financial institutions would not provide financing for the project over the 30-year life of the project, but did offer a maximum 10-year period for financing.

311. GSU's annual total system carrying costs on gas inventory stored in the Spindletop storage facility is approximately $311,200.

312. GSU did not include these carrying costs in its proposed fuel factor calculation filed with its application.

313. GSU's request for reconcilable classification of the gas inventory carrying costs is premature.

314. The carrying costs on gas are base rate costs.

315. GSU treats its inventories of coal and fuel as base rate items.

316. There is no credible evidentiary showing sufficient to support GSU's request for a good cause exception to treat the carrying costs as reconcilable.

317. It is reasonable to exclude incentive rate expense from the fuel factor calculation.

318. GSU did not include any off-system sales in its proposed fuel year.

319. GSU has made off-system sales for the last 17 years and averaged over 438,000 MWH per year during that period.

320. During the reconciliation period, GSU averaged 303,542 MWH in off-system sales per 12-month period.

321. It is reasonable to include off-system sales adders in the fixed fuel factor calculation as recommended by Calvert.

322. Because the fuel factor calculation involves prospective treatment, there is a plausible policy argument in favor of splitting the adders between the ratepayers and shareholders in order to provide GSU with an incentive to pursue off-system sales above the test year level; otherwise, any off-system sale on a going-forward basis is a net loss unless GSU can recover the variable costs caused by the sale.

323. It is reasonable to split the adders on a prospective basis between the ratepayers and shareholders 75/25 percent in favor of the ratepayers.

324. GSU included $82,862,267 in purchased power costs in its projected fuel year. Of this amount, $62,423,142 constitutes the NISCO-related purchase power expenses, leaving $20,439,125 of non-NISCO purchased power payments in GSU's projected fuel year.

325. The non-NISCO purchased power expenses consist of energy associated with GSU's buyback agreement for Nelson 6 with Sam Rayburn Municipal Power Agency (SRMPA), replacement energy purchases from Entergy, and purchases from the Toledo Bend Dam and various cogeneration sources.

326. General Counsel witness Mr. Neeley did not include any other purchased power in his fuel year estimate other than the NISCO-related purchased power payments.

***116** 327. It is reasonable to adjust Mr. Neeley's proposed purchased power cost to account for all other power purchases as proposed by GSU. To make this adjustment, GSU's purchased power estimate for the first six months of **1993** should be annualized and Mr. Neeley's gas usage should be revised accordingly.

328. GSU included 100 percent of its NISCO purchased power payments, or $62,423,142, in its projected fuel year.

329. Based on NISCO payments of $62,423,142 for the fuel year, the amount above avoided cost is $36,890,000 on a total company basis, or $16,603,865 for GSU's Texas jurisdiction.

330. For the reasons stated in Section V.C. of the Report, the portion of GSU's NISCO payments above avoided cost should be excluded from the fixed fuel factor calculation.

331. GSU's projected dispatch of Big Cajun II, Unit 3 will increase because of the relatively low cost of coal there.

332. Calvert's proposed redispatch of Big Cajun II, Unit 3 is inappropriately based on the premise that GSU is entitled to incremental pricing under the JOPOA.

333. It is reasonable to adopt GSU's position that the increase in Big Cajun II, Unit 3 generation will offset spot gas purchases.

334. The jurisdictional allocator should be calculated using at-plant data, but excluding the effects of company use and reserve station service.

335. In Examiner's Order No. 12, issued May 13, 1992, GSU was ordered to reimburse the cities, on a monthly basis, for 90 percent of their monthly expenses related to this docket.

336. Beaumont and Calvert requested the following actual and estimated expenses relating to their participation in this docket:

Party	Requested[FN*] Actual Expenses	Estimated Future Expenses	Total
Beaumont	$ 341,820.66	$ 83,179.34	$ 425,000.00
Calvert	276,495.63	128,327.60	404,823.23
Total	$ 618,316.29	$ 211,506.94	$ 829,823.23

* The actual expenses are through October 31, 1992.

337. GSU took no position regarding the reasonableness of the expenses incurred by the two groups of cities.

338. Except for a few minor disallowances recommended by General Counsel witness Ms. Schultz, no party contested the amount of actual expenses incurred by the cities through October 31, 1992.

339. Mr. Pous informally audited the invoices and other documentation submitted by the law firm of Butler, Porter, Gay & Day (BPGD), Counsel for Beaumont. He found that the individual charges and rates were reasonable compared to charges for similar services, and that the hours billed were reasonable. The hourly rate for attorneys of BPGD is $150 per hour.

340. There were no errors in the calculation nor any double billing of charges. There were no instances in which any of the charges had been recovered through reimbursement of other expenses or through billings to other entities.

341. The actual amount of rate case expenses incurred by BPGD through October 31, 1992, is $154,711.53. This amount is comprised of $141,063 in fees and $13,648.53 in out-of-pocket expenses. The projected expenses for legal representation through the completion of this docket and subsequent court proceeding is estimated to be $225,000.

***117** 342. DUCI, consultant for Beaumont, incurred fee-related charges of $179,906.25 and expenses of $7,202.88 through October 1992. Therefore, the total level of actual charges through October 1992 for DUCI is $187,109.13. DUCI estimated that the total level of charges for this case would be $200,000. The estimated amount is comprised of $192,500 in fees and $7,500 in out-of-pocket expenses and includes the actual fees and expenses incurred through October 1992.

343. DUCI's overall average hourly labor rate is approximately $95 per hour.

344. Mr. Pous informally audited the invoices and other documentation of DUCI. There were no errors in the calculation nor any double billing of charges, and no instances in which the charges have been recovered through reimbursement of other expenses. There were no expenses or charges that should have been assigned to another jurisdiction.

345. Through October 1992, the charges for services provided by Jo Campbell, Counsel for Calvert, is $100,702.05. Ms. Campbell's estimate of charges for services for the remainder of this case and any subsequent court proceedings is $93,100. Therefore, the total charges, actual and estimated, for legal services rendered on Calvert's behalf is $193,802.05.

346. Mr. Daniel performed an informal audit of Ms. Campbell's invoices and other supporting documents and verified the accuracy of the charges shown on the invoices. There was no double billing of charges, none of the charges had been recovered from other sources, and none of the charges should have been billed to others.

347. Jo Campbell's $150 per hour fee is reasonable given her prior experience, and compares favorably with hourly fees charged by other attorneys providing similar service.

348. The hourly rates of GDS personnel, Calvert's consultant, range from $28 per hour to $140 per hour. These hourly rates compare favorably with a survey of similar consulting firms in the utility consulting business.

349. Mr. Daniel performed an informal audit of GDS's invoices and supporting documentation. He deleted $360 from GDS' expenses. There was no double billing of charges, none of the charges had been recovered from other sources, and none of the charges should have been billed to others.

350. The total amount of Calvert's requested rate case expenses for legal and consulting services, including additional estimated expenses, is $405,183 minus $360, or $404,823.23.

351. General Counsel witness Ms. Susan Schultz reviewed the expenses. For professional services, Ms. Schultz required a brief, specific description of the work performed, the number of hours worked, and the hourly billing rate for each individual for which reimbursement was requested. For travel expenses, she required a copy of the original invoice or receipt. For internal expenses such as copying or supplies, she required documentation indicating quantity and the total amount charged.

352. Ms. Schultz verified the arithmetical accuracy of the invoices, receipts, and supporting documentation. She did not find any evidence of double billing of charges. With two limited exceptions, she found the requested actual expenses and individual hourly billing rates to be reasonable.

***118** 353. Ms. Schultz' recommended actual rate case expenses through October 1992 are as follows:

Party	Recommended Actual Expenses
Beaumont	
Legal	$ 154,702.47
DUCI	187,071.63
Total	$ 341,774.10
Calvert	
Legal	$ 100,702.05
GDS	175,793.58
Total	$ 276,495.63 =
Grand Total	$ 618,269.73

354. Except for a $9.06 disallowance for Beaumont and a $360 voluntary reduction by Calvert, no party contested the reasonableness of cities' actual incurred expenses and fees through October 1992.

355. The cities' actual incurred rate case expenses through October 1992 as modified by Calvert during the hearing and as recommended by Ms. Schultz should be approved.

356. In Docket No. 9030, the Commission found that the utility's expenses incurred as a result of processing a fuel reconciliation proceeding were not fuel-related costs. *Petition of General Counsel For a Fuel Reconciliation For Southwestern Public Service Company*, Docket No. 9030, 17 P.U.C. BULL. 395, 460-461, 471 (June 3, 1991).

357. In Docket No. 10035, the Commission approved a stipulation in a fuel reconciliation proceeding which included the intervening city's rate case expenses as fuel-related costs. *Application of West Texas Utilities Company to Reconcile Fuel Costs and For Authority to Change Fixed Fuel Factors*, Docket No. 10035, 17 P.U.C. BULL. 545, (Sept. 30, 1991)(mem.).

358. Based on the Commission's decision in Docket No. 9030, GSU's request to recover the cities' reimbursed litigation expenses through the fixed fuel factor in this proceeding should be denied.

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.

360. All fuel-related affiliate expenses considered in this case, with the exception of the NISCO costs above GSU's avoided cost, were reasonable and necessary. The prices the non-NISCO affiliates charged GSU were no higher than prices charged by the affiliate to its other affiliates or divisions or to unaffiliated person or corporations for the same item or class of items.

B. Conclusions of Law

1. GSU is a public utility as defined in Public Utility Regulatory Act (PURA), Tex. Rev. Civ. Stat. Ann. art. 1446c (Vernon Supp. **1993**) § 3.

2. The Commission has jurisdiction in this proceeding pursuant to PURA §§ 16, 17(e) and 43(g).

3. GSU gave notice of this proceeding as required by P.U.C. PROC. R. 21.22(b)(4).

4. An expense is not an allowable reconcilable fuel cost to the extent it resulted from a utility's imprudence.

5. Prudence is the exercise of that judgment and the choosing of one of that select range of options which a reasonable utility manager would exercise or choose in the same or similar circumstances given the information or alternatives available at the point in time such judgment is exercised or option is chosen.

***119** 6. There may be more than one prudent option within the range available to a utility in any given context. Any choice within the select range of reasonable options is prudent, and the Commission should not substitute its judgment for that of the utility. The reasonableness of an action or decision must be judged in light of the circumstances, information, and available options existing at the time, without benefit of hindsight.

7. An isolated error or failure to identify or correct an isolated problem can constitute imprudence. Whether it does or not depends upon whether the utility's conduct accords with the prudence standard.

8. The doctrine of collateral estoppel applies to relitigation of ultimate issues; it does not bar relitigation merely because the outcome of two cases may appear to be inconsistent. *Tarter v. Metropolitan Savings & Loan Association*, 744 S.W.2d 928-929 (Tex. 1988).

9. The first clause of PURA § 3(i)(6) requires a finding of the actual exercise of substantial influence or control over the public utility by the alleged affiliate. The third clause of PURA § 3(i)(6) requires a finding that the person or corporation is under common control with a public utility, such control being the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of another. Unlike the first clause, the third clause does not require actual exercise of substantial influence or control.

10. GSU and NISCO are affiliates under PURA § 3(i)(6).

11. Under PURA § 41(c)(1) and *Rio Grande*, the appropriate perspective is from the perspective of the buyer of the affiliate service, in this case GSU and other potential buyers of the service provided by NISCO.

12. Because there are no other buyers of the service provided by NISCO, it is appropriate to apply a market test to determine the reasonableness of the NISCO transaction under the first requirement of the *Rio Grande* test.

13. The intent in structuring the NISCO venture is irrelevant to whether the effect of the NISCO agreement results in GSU having the power to direct or cause the direction of the management and policies of NISCO, or vice versa.

14. GSU failed to show that the affiliate expenses in the NISCO transaction are just and reasonable under PURA § 41(c)(1) and P.U.C. SUBST. R. 23.23(b)(2)(H)(iv).

15. Approval of GSU's request to classify carrying costs as reconcilable will preclude the Commission in a subsequent fuel reconciliation case from deciding that the carrying costs should be treated in another manner.

16. The Commission has the discretion to allocate profits from off-system sales if the ordered allocation is supported by the facts and policy considerations in the record.

17. The intent of the Fuel Rule is that the fuel factor should be developed using information relating to the period in which the fuel factor is expected to be in effect - the fuel year. P.U.C. SUBST. R. 23.23 (b)(2)(C).

***120** 18. All known or reasonably predictable fuel costs, whether fixed or variable, and not specifically excepted by the Fuel Rule, should be included in the fixed fuel factor. *Application of Texas Utilities Electric Co. for Authority to Change Rates*, Docket No. 9300, Finding of Fact No. 223, 7 P.U.C. BULL. 2057, 2777 (September 27, 1991).

19. A fuel reconciliation proceeding is a ratemaking proceeding. *Application of El Paso Electric Company for Authority to Change Rates*, Docket No. 9165, 16 P.U.C. BULL. 605, 772, 1029 (August 22, 1990).

20. The cities are entitled to reimbursement of reasonable expenses under PURA § 24.

21. $116,740,170 of GSU's requested fuel cost balance should be disallowed because GSU failed to meet its burden of proof under PURA §§ 39(a) and 41(c)(1), P.U.C. SUBST. R. 2323(b)(2)(H)(i)-(iv), and the Texas Supreme Court test regarding those costs.

22. Except as indicated otherwise in the Examiner's Report, GSU met its burden of proof under PURA §§ 39(a) and 41(c)(1) and P.U.C. SUBST. R. 23.23(b)(2)(H)(i)-(iv) regarding costs it requested be treated as allowable reconcilable fuel expense for the reconciliation period. *Respectfully submitted, BETH BIERMAN ADMINISTRATIVE LAW JUDGE*

APPROVED this 21st day of April **1993**.

ATTACHMENT A

PROCEDURAL TIMELINE

Date	*Event*
01-21-92	GSU files application in Docket No. 10894 to reconcile its fuel costs, establish new fixed fuel factors, and recover its underrecovered fuel costs
02-20-92	First prehearing conference
03-30-92	Beaumont et al. files motion requesting reimbursement of rate case expenses on a monthly basis
03-31-92	Protective order entered;

	Order entered establishing procedures for objections to RFIs based on claims of privilege or exemption; Second prehearing conference
04-07-92	GSU files its index of privileged documents
04-27-92	Third prehearing conference; ALJ issues oral ruling declassifying certain information previously classified as confidential
05-01-92	GSU appeals ALJ's oral ruling requiring disclosure of confidential information
05-11-92	GSU files motion to consolidate Docket No. 10894 with the remand of Docket No. 7147
05-12-92	GSU files a list of the confidential fuel contracts that were signed after the filing of its application
05-13-92	ALJ grants Cities' (Beaumont and Calvert) requests for reimbursement of expenses in Order No. 12
05-15-92	GSU files proof of notice and publishers' affidavits
05-18-92	Fourth prehearing conference; ALJ issues oral ruling denying GSU's motion to consolidate
05-19-92	Burlington Northern Railroad Company, the Kansas City Southern Railway Company, and Louisiana & Arkansas Railway (the 'Railroads') file Appearance in Support of Interim Appeal of ALJ's oral ruling during third prehearing conference
05-21-92	Order on Interim Appeal; the Railroads' claim of confidentiality is remanded to the ALJ
05-26-92	GSU appeals ALJ's Order No. 12 of May 13, 1992, ordering it to reimburse municipal litigation expenses on a monthly basis
05-28-92	GSU files a publisher's affidavit not available for the May 15, 1992, filing
06-03-92	ALJ issues Order No. 16 establishing procedures for considering the Railroads' claims of confidentiality
06-08-92	Fifth prehearing conference
06-29-92	Sixth prehearing conference
07-08-92	ALJ issues Order No. 21 ruling on the Railroads' claims of confidentiality
07-20-92	Seventh prehearing conference
08-17-92	Eighth prehearing conference
08-28-92	GSU files motion for continuance due to delays caused by Hurricane Andrew
09-02-92	ALJ issues Order No. 30 granting GSU's motion for continuance and rescheduling hearing on the merits for October 8, 1992
09-23-92	ALJ issues Order No. 34 regarding GSU's filing of confidential material not under seal
09-25-92	GSU appeals Order No. 34
09-29-92	Commission votes to hear appeal of Order No. 34
10-02-92	Hearing on confidentiality begins
10-07-92	ALJ issues Order No. 37 ruling on request for change in confidential designation of certain documents, alleged confidentiality of documents intended to be used on cross-examination, and alleged waivers of confidentiality
10-08-92	Hearing on the merits begins
10-12-92	GSU withdraws appeal of Order No. 34
10-16-92	GSU appeals Order No. 37
10-19-92	The Railroads file Second Appearance in Support of GSU's Appeal of Order No. 37
10-21-92	Commission extends time for ruling on appeal of Order No. 37

	to November 10, 1992
11-06-92	Hearing on the merits adjourns
11-10-92	Order signed ruling on appeal of Order No. 37
12-14-92	ALJ sends letter to parties about nonconfidentiality of sealed exhibits and transcript
12-15-92	GSU files letter stating that General Counsel Ex. 6B, Schedules BA-4 and BA-10 remain confidential

ATTACHMENT B

COUNTIES SERVED BY GSU

Brazos	Madison
Burleson	Milam
Chambers	Montgomery
Falls	Newton
Galveston	Orange
Grimes	Polk
Hardin	Robertson
Harris	San Jacinto
Jasper	Trinity
Jefferson	Tyler
Leon	Walker
Liberty	Washington
Limestone	

***121** NEWSPAPERS IN WHICH NOTICE OF APPLICATION PUBLISHED*

Beaumont Enterprise Brenham Banner-Press Citizen-Tribune Cleveland Advocate Conroe Courier East Texas Banner Galveston Daily News Hearne Democrat Houston County Courier Houston Post Huntsville Item Madisonville Meteor & Times Marlin Democrat Mexia Daily News Navasota Examiner-Review Newton County News Normangee Star Orange Leader Polk County Enterprise Port Arthur News Rockdale Reporter & Messenger San Jacinto News Times Silsbee Bee The Eagle The Progress Vindicator

ATTACHMENT C

INTERVENOR CITIES

Collectively known as 'Beaumont': Beaumont Chateau Woods China Conroe Devers Madisonville Nederland North Cleveland Oak Ridge North Panorama Village Port Arthur Port Neches Riverside Todd Mission Trinity Vidor West Orange Willis

Collectively known as 'Calvert': Calvert Kosse

ATTACHMENT D

PARTIES AND REPRESENTATIVES

Party	*Representative*
GSU	Casey Wren Kerry McGrath

	Walter Demond John Williams
TIEC (Big Three Industries, Inland-Orange, Inc., Olin Corporation, Temple-Inland Forest Products Corporation, and Union Carbide Industrial Gases, Inc.)	Jonathan Day Rex D. VanMiddlesworth Frederick D. Junkin
OPC Cities of Calvert and Kosse Cities of Beaumont, China, Conroe, Devers, Groves, Madisonville, Oak Ridge North, Panorama Village, Port Arthur, Port Neches, Riverside, Trinity, Vidor, West Orange, Willis	Marion Taylor Jo Campbell Barbara Day Don R. Butler
General Counsel	Jess Totten Thomas Brocato
North Star Steel Texas, Inc.	Philip L. Chabot, Jr. Peter J.P. Brickfield

ORDER

In open meeting at its offices in Austin, Texas, the Public Utility Commission of Texas (Commission) finds that this docket was processed by an Administrative Law Judge (ALJ) in accordance with applicable statutes and Commission rules. The Examiner's Report, containing findings of fact and conclusions of law, is *ADOPTED and INCORPORATED* by reference into this Order, with the following modifications:

1. For the reasons expressed in open meeting, the findings of fact and conclusions of law appended to this Order as Attachment 1 are *ADOPTED and INCORPORATED* into this Order in lieu of the ALJ's proposed findings of fact and conclusions of law. The findings of fact and conclusions of law adopted herein modify or delete the ALJ's proposed Findings of Fact Nos. 12, 22, 23, 250, 264, 267, 268, 336, 338, 341, 342, 345, 350, 353, 354 and 355. The Commission also adds Findings of Fact Nos. 11A, 268A, 310A, and 315A to the findings proposed by the ALJ. 2. Those portions of the discussion in the Examiner's Report that recommend findings of fact or conclusions of law contrary to those appended to this Order are *NOT ADOPTED*.

The Commission further issues the following order:

1. Gulf States Utilities Company's (GSU's) application for reconciliation of its fuel costs is *GRANTED* to the extent recommended in the Examiner's Report, as modified herein. [20] 2. The pleadings filed by Texas Industrial Energy Consumers (TIEC) on May 21 and June 1, **1993**; by GSU on May 27, **1993**; and by the City of Beaumont, et al. (Beaumont) on June 1, **1993** are *DEEMED* not part of the record in this docket in accordance with the P.U.C. PROC. R. 21.144. 3. GSU is currently in litigation with Cajun Electric Power Cooperative (Cajun Electric) concerning the Joint Ownership Participation and Operating Agreement (JOPOA). The issues regarding reconciliation of coal costs incurred by GSU at Big Cajun II, Unit 3 during the reconciliation period at issue in this docket are *SEVERED* from this docket and *ABATED*. The regulatory treatment of the recovery related to the incremental coal issue, if any, will be determined in an appropriate proceeding after the litigation is concluded. A new docket, Docket No. 12104, *Inquiry into the Reconciliation of Coal Costs Incurred by Gulf States Utilities Company at Big Cajun II, Unit 3*, is established for this inquiry. GSU *SHALL* file a report in Docket No. 12104 regarding the resolution of the dispute with Cajun Electric, including the general terms of the resolution, the amount, if any, that will be paid to GSU, and the costs of the litigation. 4. The parties' Stipulation Concerning Rate Year Fuel Costs, presented by the parties during the June 2, **1993**, open

meeting, is *ADMITTED* into evidence in this docket, and the results of that Stipulation are *APPROVED*. 5. The parties' Stipulation Concerning Refund, presented by the parties during the June 16, **1993**, open meeting, is *ADMITTED* into evidence in this docket, and the results of that Stipulation are *APPROVED*. 6. The General Counsel's Motion to Admit Late-Filed Exhibit are *GRANTED*. The affidavits of General Counsel witness Ms. Susan Schultz, filed on May 12, **1993** and June 15, **1993**, and the workpaper entitled 'Updated City Rate Case Expenses' provided during open meeting on June 16, **1993**, are *ADMITTED* into evidence in this docket. 7. The General Counsel's Motion to Take Administrative Notice of the Commission approved rate of interest of 3.87 percent in P.U.C. SUBST. R. 23.45(g) is *GRANTED*. 8. Consistent with the Commissioners' comments during open meeting, a rulemaking proceeding regarding rate case expense issues is established in Project No. 12105, *Rulemaking Regarding Rate Case Expenses*. 9. Consistent with the Commission's decision in this docket, and consistent with the parties' Stipulation Concerning Refund, GSU *SHALL* refund to its ratepayers the overrecovery found by the Commission, including interest as ordered herein, over a twelve-month period. Information regarding the refunds shall be filed in compliance with the Stipulation Concerning Refund. 10. Within 20 days after the date of this Order, GSU shall file with the Commission six copies of all pertinent tariff sheets revised to incorporate all of the directives of this Order and shall serve one copy upon each party of record. No later than ten days after the date of the tariff filing by GSU or the signing of the Final Order, whichever date is later, the parties may file any objections to the tariff proposal and the General Counsel shall file the staff's comments recommending approval, modification, or rejection of the individual sheets of the tariff proposal. Responses to objections shall be filed no later than 15 days after the filing of the tariff or the signing of the Final Order, whichever date is later. The Hearings Division shall by letter approve, modify, or reject each tariff sheet, effective the date of the letter, based upon the materials submitted to the Commission under the procedure established herein. The tariff sheets shall be deemed approved and shall become effective upon the expiration of 20 days after the date of filing, in the absence of written notification of approval, modification, or rejection by the Hearings Division. In the event that any sheets are modified or rejected, GSU shall file proposed revisions of those sheets in accordance with the Hearings Division letter within ten days after the date of that letter, with the review procedures set out above again to apply. Copies of all filings and of the Hearings Division letter(s) under this procedure shall be served on all parties of record and the General Counsel. 11. All motions, applications, and requests for entry of specific findings of fact and conclusions of law and any other requests for relief, general or specific, are *DENIED* for lack of merit if not expressly granted herein.

CONCURRENCE AND DISSENT

***122** I concur with the Commission's Order except with respect to the twelve-month refund period ordered by the majority. On that issue, I respectfully dissent.

SIGNED AT AUSTIN, TEXAS this 6th day of July **1993**.

I concur with the Commission's Order except with respect to the majority's decision to allocate the fuel year off-system sales adders between GSU and GSU's ratepayers. I would allocate one hundred percent of these fuel year adders to the ratepayers, consistent with the terms of the Commission's new fuel rule.

SIGNED AT AUSTIN, TEXAS this 6th day of July **1993**.

CONCURRENCE AND DISSENT

I concur with the Commission's Order except on the issues discussed below. On those issues I respectfully dissent.

Reconciliation Period and Fuel Year NISCO costs. I would adopt the General Counsel's alternative methodology presented in brief rather than disallow the NISCO costs above avoided cost as the majority has done in this case. There is demonstrated harm to the ratepayers if the industrial customers had left GSU's system for cogeneration alternatives. Everyone should shoulder the burden of keeping those customers on line so that ultimately the ratepayers will pay less.

Reconciliation Period Off-System Sales Adders. Consistent with prior decisions of this Commission, I would allocate the reconciliation period off-system sales adders 75 percent to the ratepayers and 25 percent to GSU. This allocation represents a fair and equitable split between the utility and its ratepayers.

River Bend Division I Diesel Work. I dissent from the majority's decision to disallow $1,584,012 in fuel costs related to the Division I diesel generator work during the second refueling outage.

River Bend Diesel Generator Exhaust Fire. I dissent from the majority's decision to disallow $342,655 in fuel costs for the diesel generator exhaust fire during River Bend's third refueling outage.

Cities' Rate Case Expenses. I would deny the General Counsel's request for good cause to file the updated rate case expense affidavits. Because I do not believe that this Commission has the legislative authority to admit or approve rate case expenses in fuel reconciliation proceedings, I would deny their recovery.

GSU's Recovery of Reimbursed Cities' Rate Case Expenses. I dissent from the majority's decision to deny GSU recovery of the rate case expenses it has paid to the Cities' lawyers and consultants in this docket. It is inequitable and improper to permit the Cities' lawyers and consultants to collect rate case expenses during a fuel reconciliation proceeding, but then prevent the utility from recovering those very expenses through its fuel factor.

SIGNED AT AUSTIN, TEXAS this 6th day of July **1993**.

TABULAR OR GRAPHIC MATERIAL SET FORTH AT THIS POINT IS NOT DISPLAYABLE

A. Findings of Fact

1. On January 21, 1992, Gulf States Utilities Company (GSU) filed an application requesting reconciliation of its fuel and purchased power costs during the reconciliation period beginning October 1, 1988, through September 30, 1991, with the exception of: (1) NISCO purchased power expense, for which the beginning of the fuel reconciliation period is September 15, 1988; and (2) Nelson Unit 6 rail transportation costs under contracts with Burlington Northern Railroad Company and Kansas City Southern Railway Company (the Railroads), for which the beginning of the fuel reconciliation period is December 1, 1986.

***123** 2. GSU published notice of this proceeding once each week for four consecutive weeks in newspapers of general circulation in each county containing territory affected by the proposed changes. In addition, GSU provided direct notice to its customers by bill insert, and mailed notice to the mayors and city councils of the affected municipalities, and to the county judges and commissioners of the affected counties.

3. The Office of Public Utility Counsel (OPC), Texas Industrial Energy Consumers (TIEC), North Star Steel, the City of Beaumont, et al. (Beaumont), the City of Calvert, et al. (Calvert), and the General Counsel participated in the proceeding. The hearing convened on October 1, 1992, and was finally adjourned on November 6, 1992. There is no jurisdictional deadline in this case.

4. The booked cost of gas purchased from UTTCO during September 1991 was $3.14/MMBtu. The actual cost of gas purchased from UTTCO during September 1991 was $1.7509/MMBtu. Consequently, the booked cost of gas exceeded the actual cost by $434,262. GSU credited the $434,262 as a prior period adjustment (PPA) in October 1991 which would be addressed in GSU's next fuel reconciliation proceeding.

5. There is no credible evidence that the UTTCO PPA was intended to increase cash flow.

6. If all the PPAs for October 1991 had been applied to the September 1991 balance, GSU's underrecovery balance would have increased by $925,938.

7. The UTTCO PPA should not be adjusted in this fuel reconciliation proceeding. Absent evidence which would suggest intentional wrongdoing, PPAs should be adjusted during the appropriate fuel reconciliation period and not outside that period.

8. GSU's minimum take obligation under the Exxon contract is based on a daily average over a six-month period. If GSU does not take the minimum over that period, it has to pay a take-or-pay penalty. Therefore, to avoid that penalty, GSU must carefully plan its gas take over the six-month period.

9. Going into December 1989, GSU had balanced its purchases under the Exxon contract such that, if GSU had taken the minimum obligation for the month of December 1989, it would not have incurred a take-or-pay penalty.

10. GSU could not have foreseen the extreme harshness of the weather in late December 1989 and the resulting increase in demand.

11. GSU reasonably balanced its takes under the Exxon contract for the six-month period ending December 1989.

11A. In most months of the reconciliation period, natural gas was available on a spot basis at a price that was lower than the price for gas under GSU's long-term contracts. Mr. Bivens recommended disallowances for the Rotherwood/Eastex long-term contract and for the Exxon contract for June 1989 and December 1990, in instances in which GSU's purchases exceeded its minimum-take requirements, and cheaper spot gas was available.

12. GSU did not specifically rebut Mr. Bivens' proposed disallowances with respect to the Rotherwood/Eastex contract, and his proposed disallowance for the Exxon contract for June 1989 and December 1990. GSU has not demonstrated why it exceeded its minimum-take requirements under the Rotherwood/Eastex long-term contract and under the Exxon contract for June 1989 and December 1990, why it failed to buy cheaper spot gas and why, instead, it bought gas under the long-term contracts. These disallowances should be adopted, resulting in a disallowance of $18,500 on a total company basis.

***124** 13. Big Cajun II consists of three 540 MW coal-fired generating units. Cajun Electric is the majority owner and operator at Big Cajun. GSU is a joint owner with a 42 percent undivided ownership interest (or 227 MW) in Big Cajun II, Unit 3.

14. The coal supply for the unit is purchased by Cajun Electric under a coal supply contract with Triton Coal Company (Triton), a subsidiary of Shell Oil. The coal is transported to Big Cajun under transportation agreements between Cajun Electric and Burlington Northern and American Commercial Terminals, Inc.

15. GSU receives its portion of the coal purchased by Cajun Electric under the terms of the Joint Ownership Participation and Operating Agreement (JOPOA) for Big Cajun II, Unit 3 executed between GSU and Cajun Electric.

16. Just prior to the beginning of, and during, the reconciliation period, Cajun Electric negotiated with the coal supplier and transporters for incremental coal in excess of the minimum contract requirements to be purchased and delivered at reduced incremental prices.

17. Cajun Electric did not allow GSU to benefit from this lower-priced incremental coal.

18. As a result of GSU's exclusion by Cajun Electric from the benefits of this lower-priced incremental

coal, GSU's ratepayers will pay higher coal prices.

19. GSU first learned of Cajun Electric's October 1987 contract with Triton for incremental coal purchases in late 1987.

20. From October 1987 through mid-1991, Cajun Electric continued to enter into contracts or agreements for incremental coal purchases and pricing to the exclusion of GSU. Similarly, Cajun Electric was able to procure incremental rail and barge rates to GSU's exclusion.

21. GSU did not always get timely information from Cajun, and frequently was not permitted to review the contracts in an unedited form.

22. On November 8, 1990, GSU filed an amended counterclaim against Cajun Electric in U.S. District Court, Middle District of Louisiana, alleging that Cajun Electric violated its fiduciary duties as agent to GSU, and had breached the terms of the JOPOA, by not allowing GSU to benefit from the lower-priced incremental coal. If a decision or settlement in this lawsuit results in compensation from Cajun Electric to GSU related to the cost of fuel for the Big Cajun generating unit, GSU's customers should share in the benefits of the resolution of the lawsuit.

23. It is appropriate to defer ruling on the incremental coal issue until the federal litigation is concluded, whether by order of the court, by settlement of the parties, or other manner. GSU should be required to report to the Commission the resolution of the dispute with Cajun Electric, including the general terms of the resolution, the amount, if any, that will be paid to GSU, and the costs of the litigation. The regulatory treatment of the recovery related to the incremental coal issue, if any, will be determined in an appropriate proceeding after the litigation is concluded.

***125** 24. GSU renegotiated the rail transportation contract for Nelson 6 during the reconciliation period. Negotiations began on June 6, 1989, the earliest possible date under the 1984 rail transportation contract. These discussions continued until August 13, 1990; on February 26, 1991, they began again.

25. Price adjustments under the Nelson 6 rail transportation contract are made on a quarterly basis, and the effective date of any amendment during the renegotiation is the first day of the subsequent calendar quarter.

26. If negotiations had resumed before January 1, 1991, then that date would have been the operative effective date for any amendments.

27. Negotiations had reached an impasse in August 1990.

28. The Railroads would not negotiate the provision giving the Railroads the exclusive right to deliver coal to Nelson Station.

29. The finalized contract will be between $19 million and $22 million less than the Railroads' earlier proposals.

30. GSU handled the renegotiation of the Nelson 6 rail transportation contract in a reasonable manner.

31. By agreement of the parties in GSU's last rate case, the cost of transporting coal to Nelson 6 was deferred until the next fuel reconciliation proceeding. *Application of Gulf States Utilities Company for Authority to Change Rates*, Docket No. 8702, Finding of Fact Nos. 52 and 55, 17 P.U.C. BULL. 703, 1004-1005 (March 22, 1991). The amount to be reconciled is $59,797,402 for the period December 1986 through September 1988. Because no party to this docket recommended a disallowance of these costs, no disallowance should be imposed.

32. In 1988, GSU transferred two gas-fired units from its Nelson Generating Station in Lake Charles, Louisiana, to the Nelson Industrial Steam Company (NISCO), a general partnership organized under

the laws of the State of Texas. The NISCO partnership includes GSU and three industrial customers (the Industrial Participants): Citgo Petroleum Company (Citgo); Conoco, Inc. (Conoco); and Vista Chemical Company (Vista). Ownership interests in NISCO are as follows: Citgo, 49.5 percent; Conoco, 36.1 percent; Vista, 13.4 percent; and GSU, 1.0 percent.

33. GSU is requesting recognition of $185,094,913 in fuel costs associated with the NISCO project during the reconciliation period. This amount is comprised of $77,448,704 in avoided fuel costs and an additional $107,646,209 in fuel costs above GSU's avoided cost.

34. NISCO is a qualifying facility (QF) under the Public Utility Regulatory Policies Act of 1978 (PURPA). NISCO has entered into a buy/sell power arrangement with GSU for the power it generates at Nelson 1 and 2 and the power the Industrial Participants receive at their various delivery points associated with retail electric service with GSU. The Industrial Participants pay for power sold to them by GSU at approximately the then-current Louisiana large industrial service (LIS) rate. This rate is called the 'IPS rate.'

35. GSU pays NISCO for purchased power based on the IPS rate less a margin. During the initial gas operations phase, the margin is 5 mils. During the petroleum coke phase, the margin will be 14 percent of the difference between the IPS rate and NISCO's cost of production.

***126** 36. In late 1986, GSU filed an application under PURA § 63 for approval of its transfer of ownership of Nelson 1 and 2 to NISCO and for approval of its proposed regulatory treatment of the revenues and expenses associated with the NISCO project. *Application of Gulf States Utilities Company for Approval of a Joint Venture Cogeneration Project and Treatment of Revenues*, Docket No. 7147, 14 P.U.C. BULL. 50 (March 21, 1988).

37. In Docket No. 7147, the Commission found that the transfer of Nelson Units 1 and 2 to NISCO was in the public interest under PURA § 63 as long as the purchased power payments to the venture did not exceed GSU's avoided costs. Moreover, the Commission limited GSU's recovery of the NISCO purchased power payments from ratepayers in future rate proceedings to an amount not exceeding GSU's avoided costs.

38. On appeal, the Third Court of Appeals reversed and remanded the Commission's decision. The Texas Supreme Court subsequently affirmed the judgment of the Court of Appeals. *Public Utility Commission v. Gulf States Utilities Company*, 809 S.W.2d 201, 212 (Tex. 1991); *Gulf States Utilities Company v. Public Utility Commission*, 784 S.W.2d 519, 533 (Tex. App.-Austin 1990, writ granted).

39. The Texas Supreme Court ordered the Commission to allow GSU to recover purchased power payments to NISCO in excess of avoided costs in future rate proceedings if GSU establishes, to the Commission's satisfaction, that the payments are reasonable and necessary expenses.

40. Under the Texas Supreme Court's test, GSU must show that: (1) absent the NISCO Venture, the industrial customers would have left its system because independent cogeneration was economically more attractive than remaining in the system; (2) that the contractual rates are necessary to make the NISCO Venture more attractive than independent cogeneration; and (3) that such rates are at the minimum level.

41. If GSU satisfies the elements of this three-part test, then the Commission will determine the amount of NISCO costs, if any, GSU's ratepayers should reasonably bear.

42. The allocation of the gain on the sale is not an issue in this docket, but is instead the subject of pending Docket No. 11776, *Application of Gulf States Utilities Company for Approval of a Joint Venture Cogeneration Project and Treatment of Revenues (Remand)* (pending).

43. GSU is purchasing electricity and load retention from NISCO.

44. GSU's payments to NISCO above avoided cost are base rate load retention payments which should be considered in the context of a base rate case.

45. The Commission has previously ordered the shareholders of the utility to bear the load retention costs. *Application of Gulf States Utilities Company for Approval of Experimental Rider to Schedules LPS and LIS*, Docket No. 7309, 13 P.U.C. BULL. 1629, 1683 (May 13, 1987); *Application of Central Power and Light Company For a Large Industrial Power Experimental Rider 16*, Docket No. 7596, 13 P.U.C. BULL 858 (Sept. 25, 1987) (mem.). In GSU's last rate case, the Commission rejected GSU's request that Texas ratepayers pay non-jurisdictional load retention costs. Docket No. 8702, 17 P.U.C. BULL. at 849.

***127** 46. During the mid-1980s, GSU's industrial customers were concerned about the effect on rates of the inclusion of River Bend in GSU's rate base and the termination of certain long-term gas contracts.

47. GSU has lost 578 MW of load since 1984: 484 MW in its Louisiana jurisdiction and 94 MW in Texas.

48. Citgo's alternatives were to consider smaller generation projects using gas turbine or other gas-fired equipment, or to consider joining with other partners to pursue larger projects using the petroleum coke produced as a by-product at its refinery as a fuel. During the mid-1980s, Citgo and Conoco began discussions about the possibility of building a joint venture coke-fired generating plant on or near Citgo's refinery. Citgo also considered the installation of gas turbines.

49. In late 1984, Conoco informed GSU of its intent to pursue self-generation options.

50. Options available to Conoco were: (1) the construction of a stand-alone gas turbine project; (2) a potential joint venture petroleum coke facility with Vista; and (3) purchase of cogeneration facilities owned by PPG Industries and conversion of those facilities to coke-fired boilers. Conoco still intended to take backup power from GSU under these options.

51. GSU proposed an SUS incentive rate as an alternative to NISCO in 1986 after GSU and the Industrial Participants had begun the NISCO discussions.

52. Vista's options to NISCO included: (1) a multiple gas turbine project undertaken as a joint project among Citgo, Conoco, and Vista; (2) stand-alone gas-fired turbine generators; and (3) joint venture coke-fired projects not including GSU. Vista still intended to negotiate with GSU for standby power regardless of these options.

53. None of the Industrial Participants had approved any of the self-cogeneration options discussed and were not prepared to leave GSU's system to pursue one or more such options.

54. An incentive rate could have been structured to maintain, at least partially, some of the load on the system.

55. GSU failed to prove that the Industrial Participants would have left GSU's system absent the NISCO venture.

56. An incentive rate with a sufficient enough discount would have reduced the incentive to participate in NISCO sufficiently to overcome any long-term or short-term objections held by Conoco.

57. Conoco was indifferent to the precise price in the NISCO rate as long as the differential between the buy and sell prices was maintained.

58. The Louisiana Public Service Commission (LPSC) had required GSU's shareholders to bear the losses associated with incentive rates charged in Louisiana.

59. The total revenue reduction, for both Texas and Louisiana, associated with the SUS rates through December 1991 totals $34,231,056, which GSU's shareholders have absorbed.

60. If GSU had opted for incentive rates instead of forming NISCO, the opportunity for profit from the sale of Nelson Units 1 and 2 would have been forgone.

***128** 61. GSU has failed to prove that the NISCO contractual rates, as incorporated into the agreement, were necessary to make NISCO more attractive than cogeneration.

62. GSU did not offer any credible contemporaneous evidence of the NISCO rate negotiations which would have demonstrated that GSU held the line on the contractual rates.

63. GSU itself proposed the NISCO buy/sell formula that was ultimately incorporated into the agreement and the Industrial Participants agreed.

64. Although GSU considered the possibility of basing the NISCO buy/sell formula on its avoided cost, it never offered that option to the Industrial Participants.

65. A buy/sell formula based on avoided cost would have been much lower than the buy/sell formula actually incorporated into the NISCO agreement and would have resulted in the recognition of all NISCO costs as base rate revenue reductions in GSU's Louisiana jurisdiction.

66. Citgo would not have ruled out other pricing possibilities.

67. Depending upon when the calculation was done and whether the fixed asset payment was capitalized, the IRRs calculated for the NISCO project ranged from 25.7 to 31.1 percent on the low side and from 46 to 49 percent on the high side.

68. Expected IRRs for cogeneration alternatives ranged from approximately 20 percent to 36 percent.

69. The fact that the NISCO venture was expected to yield returns that exceeded the hurdle rate or the rate from alternative projects suggested that the final NISCO agreement was less favorable to the ratepayers than could have been achieved by effective negotiations.

70. Based on the average IPS rate of 4.4 cents per KWH during the reconciliation period, less the 0.5 cents per KWH variable service fee, the average cost per KWH purchased from NISCO by GSU was 3.9 cents per KWH.

71. GSU's avoided cost was 1.7 cents per KWH during the reconciliation period.

72. The net purchased power cost incurred by the Industrial Participants, excluding the purchase of surplus NISCO generation at GSU's avoided cost, was 1.5 cents per KWH, or 2.9 cents per KWH below the average IPS rate.

73. The actual cost of fuel used by NISCO is less than 0.5 cents per KWH.

74. GSU failed to prove that the NISCO contractual rates are at a minimum level.

75. None of the revenue received from NISCO is assigned to Texas; it is directly assigned to Louisiana.

76. The NISCO payments above avoided cost should not be borne by GSU's Texas ratepayers because those amounts are base rate load retention payments to retain load in Louisiana.

77. When fuel savings realized from not serving the Industrial Participants are netted out of the estimated $17 million in base rate revenues losses, the estimated cost of losing the three industrial customers during the first year totalled $10.9 million on a total company basis, of which $4.2 million constituted the Texas jurisdictional share. This compares with the annual Texas jurisdictional share of $14.4 million annually above avoided cost that GSU is requesting to recover in this case.

***129** 78. The potential existed that Nelson Units 1 and 2 would have been removed from rate base *regardless of NISCO.*

79. In 1988, GSU had active excess reserves equal to 987 MW, as well as 443 MW of mothballed gas capacity. Currently, GSU estimates that it has 729 MW of active capacity and 405 MW of inactive capacity available for sale. Without the sale of the two Nelson units to NISCO, the Company's reserve margin would have approached 60 percent.

80. The NISCO contract provisions requiring unanimous consent include major changes in operations or policies related to the joint venture generating facilities; adoption or revisions of the annual operating and maintenance schedule of the joint venture generating units; contracting for major purchases, fuel, and limestone; and staffing of key personnel for the joint venture.

81. These unanimous consent provisions give GSU the ability to participate in the NISCO venture far in excess of its nominal one percent ownership interest.

82. The NISCO management committee is comprised of no more than three members from each NISCO participant, including GSU. The management committee has the exclusive authority to control, manage, and direct the business of the NISCO venture and to take all actions necessary to further the purpose of the NISCO agreement.

83. None of the GSU representatives on the management committee hold an elected position with the committee.

84. There are no officers or directors of GSU which are officers and/or directors of NISCO. GSU's representatives on the management committee are not officers or directors of GSU.

85. Each participant has the number of votes which is equal to the ownership interest of the participant. All actions of the management committee require a majority of at least 65 percent of the voting power except when a unanimous vote is required. Seventy-five percent of the participants are necessary for a quorum with GSU constituting 25 percent.

86. GSU has not invoked any of the unanimous consent provisions of the partnership agreement.

87. Nearly all of the significant management policy actions by the NISCO management committee require unanimous consent.

88. Because GSU's consent is required for actions requiring unanimous consent, GSU has the power to exercise substantial influence or control over the management and policies of NISCO.

89. Withholding consent in certain instances could be used by GSU or any of the Industrial Participants as leverage in negotiations or decisions regarding policy or management.

90. Costs for modifications to GSU's common facilities at the Nelson station are required to be discussed and approved by GSU and NISCO prior to commencing any expenditure provided that approval is not unreasonably withheld.

91. GSU is the buyer of last resort if an Industrial Participant withdraws from the NISCO venture provided that GSU is not required to acquire a greater than 50 percent interest in the project.

92. NISCO has the right to initiate negotiations with GSU for the purchase of Unit 3. GSU is free to enter into negotiations about Unit 3 with any third party. If such negotiations occurred, NISCO's option on Unit 3 would be suspended until the negotiations between GSU and the third party were either completed or dissolved.

***130** 93. NISCO has the power to exercise influence and control, directly and indirectly, over the management policies and actions of GSU through the unanimous consent provisions.

94. Dr. Hadaway's alternative analysis compared the net price GSU charged NISCO with the price

GSU charged its SUS incentive rate customers rather than comparing the price NISCO charged GSU versus the price NISCO charged to other non-affiliate entities.

95. Dr. Hadaway used SUS rates as the relative comparison to NISCO's net cost because the SUS rates were the alternative load retention rates available at the time the NISCO decisions were made.

96. Because GSU does not make any other purchases of power which exceed its avoided cost, the price NISCO charges GSU far exceeds the price GSU would pay for purchased power from other sources.

97. GSU did not effectively rebut the proposition that the current NISCO price exceeds the price NISCO could charge on the open market.

98. GSU failed to present evidence proving: (1) that the expenses included in the NISCO payments do not include expenses which should be disallowed for ratemaking purposes; (2) that the allocated percentages of common facilities at the Nelson Station between GSU and NISCO are appropriate or reasonable; (3) that the costs incurred by NISCO and paid by GSU are reasonable; and (4) that the allocated amounts reasonably approximate the actual cost of service incurred.

99. The NISCO allocated costs are based on estimates.

100. Based upon a review of 1990 and 1991, GSU's payments to NISCO for power exceeded the cost of providing the service. In 1990, the NISCO costs were $49.9 million, or 20 percent lower than GSU's payments to NISCO. During 1991, the NISCO costs were $45.6 million, or 26 percent lower than GSU's payments to NISCO.

101. GSU's prudence analysis used 1985 information instead of information known or knowable to GSU in April 1988 when the NISCO agreement was consummated. It did not include any of the effects of the rate base inclusion of River Bend on GSU's rates which were known in 1988, but did include an understated IPS rate and overstated gas prices.

102. GSU's prudence analysis failed to consider the jurisdictional issue or the possibility that a portion of the Industrial Participants' load could have been maintained.

103. Dr. Hadaway's four scenarios compared customer costs with and without the NISCO venture; each used a 10 percent discount rate to bring all payments to present value status. In the first three scenarios, Dr. Hadaway used GSU's base case, high, and low marginal fuel cost estimates, respectively. The fourth scenario escalated the IPS base rate to demonstrate his contention that GSU's ratepayers were insulated from IPS base rate increases by the NISCO contract pricing provisions.

104. For his cogeneration option, Dr. Hadaway assumed that it would have taken 2.75 years for the Industrial Participants to construct their cogeneration facilities.

***131** 105. The Industrial Participants would remain on GSU's system during this construction period and pay the full standard tariff non-fuel revenue of $21.3 million per year. After the cogeneration facilities were constructed, Dr. Hadaway assumed the Industrial Participants paid stand-by fees and facility charges of $4.3 million per year.

106. Based on GSU's projected fuel year ending June 30, **1993**, the total cost of generated and purchased power estimated by GSU is $574,528,321, of which $32,008,369 is attributable to NISCO. The NISCO power costs are approximately $39.52/MWH compared to GSU's system average MWH power cost of approximately $19.25/MWH. The next highest system power cost excluding NISCO is Willow Glen 2 power at approximately $22.55/MWH. The purchased power cost from other cogenerators is $16.34/MWH.

107. In addition to reviewing the costs incurred if the Industrial Participants left the system for cogeneration and the costs incurred under the NISCO venture, Beaumont witness Mr. Lawton

analyzed GSU's option to sell Nelson Units 1 and 2 to the three industrial customers on a non-participating basis. When the sell-but-not participate option was considered, Mr. Lawton calculated that NISCO resulted in a $27,855,869 detriment to ratepayers.

108. In the calculation of computed fuel savings under the cogeneration option, Mr. Lawton used 1,517,828 MWH for the system load lost if the three industrial customers left the system as compared to Dr. Hadaway's figure of 1,411,580 MWH.

109. The actual sales level of the industrial customers was 1,517,828 MWH.

110. Mr. Lawton assumed a 100 percent capacity factor rather than Dr. Hadaway's 93 percent capacity factor because the higher capacity factor served as a proxy for calculating the revenue received by GSU for stand-by power in the event the cogeneration facility shut down. Dr. Hadaway assumed a 93 percent capacity factor but did not include any revenue that GSU would receive for additional sales of power to the industrial customers.

111. Mr. Lawton's adjustment for MWH to account for revenues received for stand-by service is not unreasonable although expecting a 100 percent capacity factor is unrealistic.

112. Mr. Lawton added $3 million per year to the estimated cogeneration stream to reflect GSU's assumptions that management services provided to the NISCO project could generate that revenue under the sell-but-not-participate option.

113. GSU estimated the value of its management services to the industrial customers under the sell-but-not-participate option as $3 to $8 million annually.

114. It is reasonable to account for the value of the management services under the sell-but-not-participate option as Mr. Lawton did.

115. Mr. Lawton deducted $4 million per year for the first ten years from NISCO's contribution to system fixed costs to account for GSU's receipt of the purchase payments from the industrial customers under the sell-but-not-participate option.

***132** 116. It is reasonable to subtract $4 million per year from the NISCO contribution to fixed cost as proposed by Mr. Lawton because his subtraction is based on GSU's expectation that it would have to return the gain on the sale to ratepayers over a five-to ten-year period.

117. GSU failed to prove that it prudently incurred the NISCO costs above its avoided cost.

118. No other cogenerators are similarly situated with the Industrial Participants.

119. During the reconciliation period, GSU's total off-system sales equalled $19,214,350. Of this amount, $14,948,275 was classified by GSU as reconcilable fuel revenue which reduced GSU's reconcilable fuel costs. The remaining $4,266,075, or adder, was classified as non-reconcilable non-fuel revenue.

120. The effect of classifying the adder as non-reconcilable is that the adder does not reduce GSU's reconcilable fuel balance and is therefore retained by the shareholders.

121. In GSU's last rate case, Docket No. 8702, the issue of whether to treat GSU's off-system sales as non-reconcilable was not contested, not argued in briefs, or presented to the Commission in oral argument.

122. Because GSU had removed the off-system sales adders from both its reconcilable fuel expense and its non-reconcilable base rate revenue requirement in Docket No. 8702, any classification of the adders in this case as reconcilable would not be a retroactive change.

123. In Docket No. 9945, EPE's last rate case, the Commission allowed EPE to retain the profits from

its off-system sale to La Comision Federal de Electricidad de Mexico (CFE) because EPE's Palo Verde Unit 3 was not included in rate base, and because EPE's financial condition was found to be extremely poor. *Application of El Paso Electric Company for Authority to Change Rates*, Docket No. 9945, Findings of Fact Nos. 212A, 216, 217, 218, 18 P.U.C. BULL. 9, 578-579 (February 6, 1992).

124. In Docket No. 8425, HL&P's off-system sales profits occurring during its reconciliation period were reconciled. *Application of Houston Lighting and Power for Authority to Change Rates*, Docket No. 8425, Finding of Fact No. 97, 16 P.U.C. BULL. 2199, 2721 (June 20, 1990).

125. In Docket No. 9300, TU Electric was required to include its test year off-system sales profit as miscellaneous revenue in calculating its revenue requirement. *Application of Texas Utilities Electric Company for Authority to Change Rates*, Docket No. 9300, Finding of Fact No. 230, 17 P.U.C. BULL. 2057, 2872 (Sept. 21, 1991).

126. GSU's off-system sales are made possible by plants that the ratepayers have paid for or are paying for now.

127. There is no credible evidence demonstrating that an incentive is necessary to encourage GSU to engage in off-system sales which have already taken place during the reconciliation period.

128. There is no credible evidence of the impact of the proposed allocation on GSU's financial strength.

129. Off-system sales are not a significant portion of GSU's business.

***133** 130. There were no dividends paid to GSU's shareholders during the reconciliation period, but there is no credible evidence as to if or how that omission has affected GSU's financial condition.

131. There is no credible evidence regarding ratepayer burdens resulting from GSU's off-system sales.

132. GSU's current base rates are based upon the test year ending in September 1988. During that test year, GSU's off-system sales totalled slightly over 1.2 million MWH which is approximately four times the current annual level of off-system sales. Incremental O&M was not removed from the test year O&M amount. Therefore, GSU's test year O&M included approximately $720,000 per year of incremental O&M for off-system sales. This is approximately $540,000 per year more than the current level.

133. GSU's current base rates include more than sufficient incremental O&M expense to cover the off-system sales which occurred during the reconciliation period.

134. There is no credible evidentiary basis for concluding that a portion of the reconciliation period off-system sales adders should be allocated to the shareholders.

135. One hundred percent of the off-system sales adders from the reconciliation period, or $4,226,075, should be treated as reconcilable in this case.

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 fuel amortization, spent fuel and interest expense.

137. River Bend Refueling Outage 2 (RFO-2) began on March 15, 1989, and ended on June 8, 1989. RFO-2 was initially scheduled to last for 60 days but actually lasted 85 days.

138. During RFO-2, the critical path schedule of the outage was delayed by work done on the Division I diesel generator.

139. The contractor selected by GSU to perform the diesel work for GSU during RFO-2, Cooper

Industries, failed to complete its work on schedule, resulting in a delay of the critical path schedule and an extension of RFO-2. There were approximately 17 days of duration variation in the Division I diesel inspection, 11 of which were a slip in the critical path schedule.

140. GSU experienced delays in Cooper's work prior to the beginning of RFO-2, and expended a considerable amount of time and effort to improve Cooper's performance.

141. The Cooper site management and planning efforts started late and caused a 'never on time' ripple effect throughout most of the outage.

142. GSU's RFO-2 Outage History Report attributed the Division I diesel generator inspection delays to the contractor's lack of familiarity with GSU procedures.

143. Work was scheduled to start on the Division II diesel generator immediately after the completion of the Division I Emergency Core Cooling System (ECCS) test. The Division II diesel generator work did not start until April 16, 1989, however, despite the fact that the ECCS test was completed on April 14, 1989.

***134** 144. The Division II ECCS test which was scheduled to be completed on April 23, 1989, was actually completed on May 12, 1989, 19 days later than scheduled.

145. River Bend has a safety tagging system to prevent the operation of plant equipment when such could cause personal injury or equipment damage. This system requires maintenance personnel to obtain a clearance to make repairs, design changes, and perform routine maintenance on plant equipment. Repeated violations of the safety tagging procedure were experienced during the first month of RFO-2.

146. On April 13, 1989, GSU issued a stop work directive which halted work by Cooper until its personnel could be retrained and an assessment of Cooper's work could be performed.

147. The stop work directive was lifted on April 14, 1989.

148. A lack of adequate training in GSU's procedures was responsible for the tagging violations.

149. NRC Inspection Report No. 89-11 found that GSU failed to take adequate corrective actions to prevent new violations of its tagging system based on the conclusion that the corrective actions taken by GSU during the first month of RFO-2 failed to determine the extent to which tagging program violations existed.

150. Due to poor performance, GSU removed Cooper's original project manager from the site during RFO-2.

151. The outage history report for RFO-2 indicates that GSU had to repair an intake manifold crack and install intake manifold braces. However, the schedule variance for RFO-2 lists Cooper's problems as the reason for the delay, not the manifold bolt repairs.

152. The 11-day delay in the critical path resulted from imprudence. The resulting increase in fuel costs of $1,584,012 on a total company basis should be disallowed.

153. After the Division I diesel generator work was finished on April 14, 1989, the reactor water cleanup system (RWCU) work was extended from 12 to 35 days. Consequently, this effort became the critical path and remained so until May 14, 1989.

154. The work which extended the RWCU outage involved a series of valve repairs and retests. Forty-eight of 208 valves tested failed the Local Leak Rate Test (LLRT).

155. Anchor Darling Valve Company (Anchor Darling) was the contractor for the valve repairs.

156. GSU issued a stop work directive on April 13, 1989 until Anchor Darling's personnel could be retained and an assessment made of Anchor Darling's work. GSU had to repair and retest a number of valves previously repaired by Anchor Darling, and eventually transferred the valve repair work to Stone & Webster in late April and early May 1989.

157. The valves at issue could not be worked on 24 hours a day. Consequently, putting more personnel on the valve job would not have solved the problem because physical size limitations restricted the number of people who could work in that area.

158. The RWCU work could not begin until the Division I ECCS test was completed. The Division I ECCS test was finished on April 14, 1989, the same date that the stop work directive was removed. The LLRT for the RWCU valves began on April 14, 1989, the first date that such work could begin.

***135** 159. GSU was able to rework and retest the valves in time to prevent further delay in the critical path of RFO-2.

160. On May 29, 1989, near the scheduled end of the second refueling outage, the B preferred transformer was energized following routine maintenance, exploded, and caught on fire, resulting in a forced outage until the installation of a replacement transformer. The forced outage to replace the B preferred transformer began at the end of the second refueling outage on June 8, 1989, and ended on June 24, 1989. It effectively resulted in a 16-day extension of the second refueling outage.

161. Prior problems with the A preferred transformer should have alerted GSU to the potential problem with the B preferred transformer because the A and B preferred transformers were capable of serving the same load.

162. The A preferred transformer initially failed on June 14, 1985. The transformer apparently experienced a number of low-side faults which probably caused progressive winding distortion that finally resulted in the failure.

163. Early in RFO-2, oil samples taken from the A preferred transformer indicated a problem with that transformer. The presence of dissolved combustion product gases in the oil sample indicates an internal arcing in the transformer.

164. After GSU discovered the dissolved gases in the A preferred transformer, GSU conducted a Doble test. The Doble test performed on the A preferred transformer showed that high excitation currents existed and that the transformer had deteriorated. The cause of this deterioration was most likely low-side or secondary faults from the auxiliary boiler.

165. The failure of the A preferred transformer was due to the inability of the transformer to handle the repeated through faults to which it had been subjected.

166. Prior to the May 29, 1989 event, the B preferred transformer energized and tripped due to secondary cable faults on May 2, 1989, and May 23, 1989. These secondary cable faults were low-side or through faults.

167. GSU performed a Doble test on the B preferred transformer on May 9, 1989, following the trip on May 2, 1989.

168. Oil samples were again taken following the May 23, 1989 trip to determine the presence of gases, but the results were once again negative. GSU decided that an additional Doble test was not warranted because the previous Doble test performed on May 9, 1989 was normal as were the oil sample results.

169. United Engineers & Constructors, Inc. (UEC) prepared an analysis of the B preferred transformer failure for GSU.

170. According to UEC, the B preferred transformer suffered mechanical damage which was caused

by excessive axial short circuit forces.

171. The auxiliary boiler had been fed by the A and B preferred transformers. The relatively frequent faults in the auxiliary boiler contributed to the transformer failures.

172. GSU should have known that the prior problems with the A preferred transformer put the B preferred transformer at risk.

***136** 173. The 16-day delay for the B preferred transformer fire was the result of imprudence. The resulting $2,245,911 in fuel costs should be disallowed.

174. River Bend Refueling Outage 3 (RFO-3) began on September 29, 1990, and ended on December 4, 1990. The outage was scheduled to last for 58 days but actually lasted 66 days.

175. A six-day delay of the outage was due to the synchronization of the Division II diesel generator out-of-phase to the grid.

176. The function of the Division II diesel generator is to provide power to the Division II equipment when off-site power is lost. During the outage, either the Division I or the Division II diesel generator must be operable.

177. On October 21, 1990, the Division II diesel generator was undergoing post-maintenance testing. During this testing, the generator was scheduled to be synchronized to the plant's electrical grid to verify that its load carrying capability had not been degraded. The process of synchronizing the diesel generator to the grid was performed by a Unit Operator, who manually closed the diesel generator's output breaker when the diesel generator and the grid voltages were in phase. In synchronizing the Division II diesel generator, however, the Unit Operator mistakenly closed the diesel generator output breaker with the generator voltage out-of-phase with that of the grid.

178. River Bend's Independent Safety Engineering Group (ISEG) prepared an analysis of the out-of-phase synchronization of the Division II diesel generator.

179. According to ISEG, the event was solely due to operator inattentiveness and failure to follow procedure. Other factors such as inadequate training, experience, and procedures did not contribute to the incident.

180. According to ISEG's analysis, if synchronization check devices had been installed at River Bend, the operator could not have closed the diesel generator output breaker at the incorrect moment.

181. In August 1985, ISEG concluded that it was possible to synchronize the diesel generator and the grid out-of-phase.

182. Synchronization occurs at least 36 times per year. ISEG recommended in 1985 that a synchronization check device be installed in the circuit breaker control circuits to prevent the breaker from connecting two out-of-phase voltages.

183. ISEG's Special Analysis report (SA 90-011) indicated that the recommendation made by ISEG in 1985 was made in the form of an Engineering Evaluation and Request (EEAR). An EEAR requests the Engineering Department to review a recommendation to determine whether it should be implemented.

184. The EEAR was not presented to the Work Scope Committee because Design Engineering characterized the requested EEAR as a betterment.

185. The failure to perform the synchronization of the Division II diesel generator to the grid was an isolated error which resulted in a delay to the third refueling outage.

186. It was not imprudent for GSU to choose not to evaluate the installation of synchronization check

devices based on ISEG's earlier analysis because: (1) the devices are not required for the safe operation of the plant; (2) the probability of an out-of-phase event is very low; (3) the operator must perform the function properly regardless of whether a synchronization check device is installed; and (4) training, experience or procedures did not contribute to the event.

***137** 187. In November 1990, a crack about one and one-half inches long was discovered in the welded connection between the Division II diesel turbo-charger exhaust and the intercooler.

188. Drawings of the weld were reviewed during the diesel's design and installation and were found to be acceptable. The vendor installed the shop weld according to those drawings. However, the gap between the pieces joined by the weld was too wide for the size of the weld specified. Once the weld was made, the gap was hidden from view.

189. A quality assurance program cannot guarantee that there will be no defects.

190. The one-day delay attributable to the diesel generator exhaust water jacket repair was not the result of imprudence.

191. On October 20, 1990, a fire occurred in the insulation around the exhaust expansion joint on the Division II diesel generator.

192. The design of the diesel exhaust system allowed a portion of the exhaust gas to blow by the expansion joint to eliminate friction and reduce loading on the turbo-charger housing.

193. The diesel had been running unloaded for approximately two and one-half hours prior to the fire. Running the diesel in such an unloaded condition can result in the presence of more unburned fuel in the exhaust gas than is normally present when the diesel is run under load.

194. GSU's Condition Report CR #90-0963 stated that the exhaust blow-by feature was not considered in the selection of jacketing materials.

195. Disallowance for the lost generation associated with approximately two days is appropriate. The fire was a direct cause of a design change, the consequences of which GSU imprudently failed to consider upon its implementation.

196. River Bend was automatically shut down on February 20, 1989. At the time, River Bend was in start-up from a previous plant outage. During the start-up, a decrease in reactor pressure caused by the opening of large steam line drain valves, without the compensation of in service turbine bypass valves, led to an automatic shutdown or scram of the reactor.

197. Main steam line drains are used to remove dense steam from the main steam line during plant operations. The valves isolating the drains are usually open during plant operation and closed during a shut down. During a reactor startup, the valves are sequentially opened. This process is controlled by General Operating Procedure GOP-001.

198. Scram 89-01 was the fourth scram at River Bend to occur under similar circumstances during a reactor start-up.

199. The ISEG report stated that keeping the turbine bypass valves in service during main steam line drain valve manipulations was one of the corrective actions adopted following Scram 86-SU-18 in January 1986. The Revision 6 of GOP-001 following Scram 86-SU-18 added the following cautionary note: If performing a Hot Startup, ensure adequate steam bypass capacity prior to opening drains which could increase steam flow.

200. When Revision 7 of GOP-001 was issued in 1987, this cautionary note was revised in a manner that did not require that the turbine bypass valves be in service during steam line drain valve operations.

***138** 201. The deletion of instructions from GOP-001 Revision No. 7 caused the reactor pressure transient which resulted in Scram 89-01. Had GOP-001 not been improperly and imprudently revised, the scram and resulting outage could have been prevented.

202. The additional fuel costs of $153,489 resulting from the forced outage of 38 hours, 55 minutes should be disallowed.

203. On June 24, 1989 and June 29, 1989, River Bend was taken out of service to repair Electro-Hydraulic Control (EHC) oil leaks on the No. 2 and No. 3 turbine control valves.

204. Use of incorrect o-ring seals in the electro-hydraulic system caused the oil leaks.

205. The Ultra-seal o-ring cannot be satisfactorily replaced with a standard o-ring. The oil leaks were due to the failure of standard o-rings where proper Ultra-seal #4 o-rings were required.

206. GE craft personnel and supervisors who worked on the turbine control valves during the refueling outage should have recognized that the Parker-Hamifin fittings required a non-standard o-ring and should have researched the proper documentation to verify the correct parts.

207. The failure to apply the proper Ultra-seal o-ring could have been avoided had reference to the appropriate cite documentation been made.

208. Following the June 29, 1989 shutdown, GSU reviewed and evaluated all gaskets and o-rings used in the turbine control valves during 1989. This review found that of six additional connections in the remaining two turbine control valves, three connections had the required Ultra-seal o-rings and three had the incorrect standard o-rings.

209. The failure to use correct o-rings was imprudent. The resulting increase in fuel cost of $400,330 on a total company basis should be disallowed.

210. On December 12, 1990, a reactor scram occurred during performance of the weekly turbine overspeed operability test.

211. The root cause of this event was an electro-hydraulic trip system pressure transient. As air is trapped in the system and compressed, a large drop in the electro-hydraulic trip system pressure occurs, allowing the disk dump valve of the other turbine steam valves to release.

212. To prevent reoccurrence of this event, GSU has installed orifices in the electro-hydraulic trip system hydraulic fluid supply lines in all the turbine steam valves.

213. GE had identified corrective action for differently designed valves approximately eight years earlier.

214. The shutoff valves utilized at River Bend are of an older GE design.

215. GE's corporate position was that installation of orifices was not required at River Bend because air entrapment was not a problem with the valves at River Bend.

216. The outage that occurred during the turbine testing on December 12, 1990 was not the result of imprudence. GSU pursued reasonable corrective action based on the information that was available to it at the time.

217. High temperature in the steam tunnels at River Bend reduced the available power to 590 MW.

***139** 218. The root cause of the high temperature was personnel error.

219. GSU changed the start-up procedure to require a check of the dampen position by operations personnel after everyone else completed work or inspection in the steam tunnel. High temperature in

the steam tunnels was not the result of imprudence by GSU.

220. Feedwater Heater High Level Dump Valve Short Cycling is a catchall derating event for a group of valves that have been leaking during the operating cycle.

221. The heat rate at the beginning of a cycle will generally be better than at the end of a cycle during refueling outages. Some losses are judged to be non-recoverable because of the expense it would take to recover them. Most of the components are located in high radiation fields and cannot be worked on during plant operation.

222. These are normal losses which occur over the operating cycle of the plant. The record indicates GSU took reasonably prudent steps to reduce or eliminate the losses.

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.

224. GSU records nuclear interest payments even when River Bend is not operating.

225. The nuclear fuel interest costs are incurred whether the plant generates power or not. They must be included in the two calculations: (1) the cost incurred during an imprudent nuclear outage and (2) the postulated cost that would have occurred had there been no outage. The end result of this double inclusion is that nuclear fuel interest components drops out of the calculation altogether.

226. If the nuclear fuel interest costs are included only in the postulated cost of nuclear generation when there is no outage, as GSU proposed in its calculation, the net effect is to allow GSU to collect those interest expenses twice.

227. In November 1988, GSU's capacity factor for Big Cajun II, Unit 3 was approximately 40 percent.

228. The fuel cost used by GSU to dispatch its share of the Big Cajun unit was $1,7646/MMBtu, which was based on the estimated cost supplied by Cajun Electric for 1988 coal purchases.

229. The October 1988 funding statement provided to GSU by Cajun Electric forecasted a price of $1.4829/MMBtu. This forecasted price included a short-payment by Cajun Electric. Cajun Electric lost its litigation with Triton and was required to make up the short-payment.

230. The revised November 1988 funding statement showed a fuel price estimate for the month of $1.7235/MMBtu, unadjusted for coal degradation.

231. Around the 20th of each month, GSU begins to determine its dispatch cost for the following month. Meanwhile, Cajun Electric receives the invoices from the coal supplier and transporters and then forwards them to GSU. The invoices for November 1988 coal supply and transportation were received by Cajun Electric in late October 1988.

***140** 232. Normally a unit should be dispatched using incremental heat rate data.

233. It is not possible to use incremental heat rate data to dispatch jointly owned units where the joint owners do not always take energy in proportion to their capacity ownership.

234. Both Cajun Electric and GSU are entitled to independently dispatch or schedule their ownership share of Big Cajun II, Unit 3. Only if both utilities take the output of the unit in direct proportion to their ownership share at all times will both utilities receive equal benefits from incremental heat rates.

235. If GSU increased its output from the Big Cajun unit based upon the incremental heat rate curve and Cajun Electric then reduced its output, the expected benefits from increasing GSU's output would not materialize.

236. Because it does not control the output of the unit and cannot predict how Cajun Electric will use the unit, GSU reasonably schedules generation from Big Cajun II, Unit 3 based on average heat rate data.

237. GSU reasonably dispatched its share of the Cajun unit in November 1988.

238. During December 1989, the first half of the month was mild but the third week was very cold. GSU had to burn oil and contract for off-system power subject to take requirements to offset curtailments of natural gas. GSU also burned long-term gas which caused it to exceed contract minimums.

239. GSU implemented the same cold-weather precautions for February 1990, which included contracting for firm supplies of short-term gas to supplement its long-term gas. February 1990's weather, however, turned out to mild in comparison to December 1989. In order to satisfy the minimum contract requirements under the long-term and short-term firm contracts, GSU had to decrease its discretionary supplies, including use of Big Cajun II, Unit 3.

240. GSU reasonably dispatched its share of the Cajun unit in December 1989 and February 1990.

241. Peaking service occurs when a unit may be taken off-line on a daily basis or over a weekend. During periods of low system load, the generating units in service must operate at lower loads, resulting in higher heat rates. If one of the units can be taken off-line instead of operated at a low load, then the load on the other units may be increased with a corresponding improvement in the system heat rate.

242. GSU's system dispatch operators would not start Sabine 5 for 72 hours after it was taken off-line, which effectively precluded Sabine 5 from being used as a peaking facility.

243. Sabine 5 was designed for peaking service and has a design turbine heat rate consistent with peaking service; its turbine, however, was not purchased with peaking modifications because GSU expected to operate the unit in a load-following mode.

244. Any potential fuel savings from operating Sabine 5 in peaking mode would be outweighed by the additional costs associated with operating it as a peaking unit.

245. Peaking service increases the stress and wear on the steam turbine components, resulting in increased maintenance and unit heat rate, and decreased reliability and life of the unit.

***141** 246. Operating Sabine 5 in the peaking mode will not result in net fuel savings. GSU reasonably utilized this unit during the reconciliation period.

247. In April 1989, Cajun Electric and GSU entered into an agreement which permitted either party to purchase energy from the other party's ownership interest in Big Cajun II, Unit 3 at $3.50/MWH, with the purchasing party responsible for supplying the fuel. During the reconciliation period, GSU sold 23,711 MWH to Cajun Electric under this agreement for $82,989, while it purchased 1,225 MWH from Cajun Electric for $4,288.

248. GSU classified the $4,288 paid to Cajun Electric as a positive reconcilable fuel expense, but classified the $82,989 payment received from Cajun Electric as non-reconcilable.

249. There is no credible evidentiary basis for treating GSU's payment to Cajun Electric as reconcilable but not so treating the receipt from Cajun Electric.

250. State and local gross receipts taxes and fees, the PUC assessment, and uncollectible expense are all a function of the total revenue received by the utility.

251. The revenue-related taxes and fees are related to the reconcilable fuel revenue, but they are also base rate items set by the Commission in a rate case.

252. The revenue-related taxes and fees associated with the overrecovery should not be disallowed in this case.

253. The Commission considered whether to adjust revenue-related taxes and fees in Docket No. 9300 and declined to do so. Docket No. 9300, 17 P.U.C. BULL. at 2619-2620, 2683 (Finding of Fact No. 392), 2729, 2825.

254. Starting in June 1991, the fuel expense related to certain of GSU's incentive rates was subtracted from GSU's total reconcilable fuel and purchased power expense before these expenses were allocated to the Texas jurisdiction and the over/underrecovery calculation was made. In addition, GSU removed the Texas incremental KWH sales from total Texas retail sales, and removed the total incremental KWH sales from the total system KWH sales.

255. Customers paying the incentive rates are not charged pursuant to the fixed fuel factor; rather, they are charged the incremental cost of fuel, whatever that cost happens to be when the customer uses electricity. To include the incremental expense and associated sales would result in both non-fixed fuel factor customers and fixed fuel factor customers being allocated an expense based on a combined incremental and system average cost.

256. Whether ratepayers are harmed by the exclusion or inclusion of incentive rate fuel expense depends upon whether incremental cost is less than or greater than system average cost.

257. Because incremental cost was less than system average cost during the reconciliation period, inclusion of incremental cost would decrease the reconcilable fuel expense.

258. It is reasonable to exclude incentive rate fuel expense from the reconcilable fuel balance.

259. Two interest rates are applicable to the refund or surcharge calculation for the reconciliation period in this case: (1) 11.48 percent, approved in Docket No. 7195, which is applicable to all interest calculations from September 1988 through February 1991; and (2) 11.94 percent, approved in Docket No. 8702, which is applicable to all interest calculations from March 1991 through September 1991.

***142** 260. GSU used the simple interest methodology to calculate the interest on its alleged underrecovery balance for this case.

261. GSU has been accruing simple interest on the deferred fuel balance during the reconciliation period.

262. Provisions in the substantive rules which require annual compounding of interest involve lower interest rates tied to shorter-term investments.

263. The Commission recently declined to adopt compound interest in Docket No. 9300.

264. It is reasonable to use the simple interest calculation in this case as recommended by GSU and the General Counsel, for the period through April 30, **1993**. For interest accrued after this date, Section 23.23(b)(2)(A) and (B) of the Commission's Substantive Rules (January **1993** amendment) requires the use of the rate of interest determined by the Commission under Section 23.45(g) of the Commission's Substantive Rules and requires compounding on an annual basis. The rate prescribed by the Commission for **1993** under this section is 3.87%.

265. P.U.C. SUBST. R. 23.23(b)(2)(G)(v) requires a one-time bill credit for implementing refunds unless it can be shown that the short time frame would be an incentive to use electricity excessively.

266. In GSU's last two rate cases, the Commission made specific findings regarding GSU's financial condition which supported approval of a longer time period than allowed by the substantive rule for accomplishing the refunds. *Application of Gulf States Utilities Company for Authority to Change Rates,*

Docket No. 7195, 14 P.U.C. BULL. 1943, 2417 (Finding of Fact No. 240) (May 16, 1988); Docket No. 8702, 17 P.U.C. BULL. at 1022, (Finding of Fact No. 56) (May 2, 1991).

267. GSU did not present evidence concerning its financial condition that would justify a longer time period for refunds than the one-time refund prescribed by Substantive Rule 23.23(b)(3)(C)(v) (January **1993** amendment). A one-time refund, however, would refund roughly 15% of the utility's annual fuel revenue in a single month. A refund of this magnitude is likely to induce customers to increase their consumption in the month of the refund or in a subsequent month. To avoid the possibility that the size of the refund will induce additional consumption, the refund should be made over a twelve-month period.

268. DELETED.

268A. The Commission's rules, Subst. R. 23.23(b)(2)(G)(iii) [§ 23.23(b)(3)(C)(iii) of the current rule], provide that a refund will be allocated among the customer classes on the basis of the historical consumption of each class during the period that the over-recovery occurred. This method of allocation should be applied to the refund in this case.

269. GSU's proposed fuel year is July 1, 1992, through June 30, **1993**, while the General Counsel proposed a **1993** fuel year.

270. GSU used PROMOD, a production cost simulation model, for its fuel factor calculations while the General Counsel used a spreadsheet analysis.

271. GSU did not rebut the **1993** fuel year proposed by the General Counsel.

***143** 272. PROMOD is generally more accurate and sophisticated than a spreadsheet analysis.

273. There are contested assumptions underlying the PROMOD modeling which are not in evidence.

274. The General Counsel's proposed fuel year is based on information projected for the time that the fuel factor will be in effect, and, as modified by ALJ, is reasonable.

275. Except as modified by the ALJ, the General Counsel's proposed fuel year is reasonable and should be adopted.

276. In August 1991, GSU and Sabine Gas Transmission Company (SGT) entered into the 1991 Amended and Restated Gas Transportation Agreement (the Transportation Agreement) which requires SGT to provide transportation and swing service to GSU in return for a transportation fee paid by GSU.

277. GSU's payments to SGT only affect the fixed fuel factor calculation in this proceeding because the Sabine Spindletop project was not in operation during the reconciliation period.

278. The Transportation Agreement provides for delivery by GSU of gas to the Texas Sabine Pipeline System and re-delivery to GSU on a delayed basis. GSU pays SGT a monthly transportation fee per MMBtu of gas delivered to SGT's pipeline system plus a charge for electricity to operate the storage facility. SGT credits a portion of the transportation fee received from GSU to the 'Non-Credit Payment;' and the remainder of the fee is credited to the 'Credit Payment.'

279. The Non-Credit Payment is an amount per MMBtu subject to adjustment and the Credit Payment is the remainder of the transportation fee in excess of the Non-Credit Payment. The Credit Payment is applied by SGT against the 'Payoff Amount' which consists of SGT's installation costs for the Spindletop facility including interest. The Payoff Amount is adjusted each month by the Credit Payment and accrued interest. When the Payoff Amount equals zero, the Credit Payment portion of the transportation fee is eliminated.

280. GSU is also required under the Transportation Agreement to deliver a minimum quantity of gas

to SGT or pay an Amortization Fee based on the minimum quantity not delivered. This minimum quantity payment is $9,000,000. When the Payoff Amount reaches zero, the minimum quantity obligation is also eliminated.

281. Under the 1991 Amended and Restated Optional Purchase and Amortization Agreement (the Optional Purchase and Amortization Agreement), GSU has the option to purchase the facilities from SGT for a sum equal to the Payoff Amount provided that the purchase price is not less than one dollar.

282. The current market value of the facilities is approximately $40,000,000.

283. Under GSU's worst case scenario, after adjusting for the minimum fuel burn at Sabine Station, expenses will average approximately $11,258,000 per year over the first seven years, but will be offset by an average annual projected savings over those seven years of approximately $11,568,000. At the end of the seventh year, GSU projects a cumulative net present value savings of $403,000 under the worst case scenario. Under GSU's expected case scenario, GSU projects a cumulative net present value savings of $48,879,000 at the end of the seventh year.

***144** 284. If the payments to SGT are recovered through the fixed fuel factor in this case, GSU has agreed to credit revenues received from the existing facility to off-set the reconcilable fuel expense.

285. In Docket No. 8425, the Commission included costs from HL&P's leased North Dayton gas storage facility in HL&P's known and reasonably predictable fuel costs.

286. The Commission found that the storage capability provided by the North Dayton storage facility was a central feature of HL&P's gas acquisition strategy. If HL&P had not separately paid for gas storage then any gas storage services purchased by HL&P would have been provided by gas suppliers and charged to HL&P through increased gas prices. This increase in gas prices would have been recovered through the fuel factor.

287. The Commission determined in Docket No. 8425 that known or reasonably predictable fuel costs may include those costs that show that the Company has planned and operated its facility and fuel-procurement programs prudently, with the objective of providing reliable power at the lowest reasonable total cost.

288. GSU's payments to SGT are reconcilable fuel costs based on the Commission's application of the Fuel Rule in Docket Nos. 8425 and 9300.

289. GSU does not have legal title to the Sabine Spindletop facility or the land upon which it is located.

290. GSU has significant authority to direct the construction, design and operation of the facilities by SGT.

291. GSU has the right to approve the budget, engineering designs, bid specifications, selection of the contractor, equipment specifications and terms of agreements between SGT and third parties regarding storage.

292. The revenue derived from third party storage is credited to GSU.

293. GSU is the manager of the construction project, operates and maintains the equipment on SGT's pipeline and provides contract administrative services to SGT.

294. SGT is precluded from expanding the facilities without GSU approval so that GSU can prevent SGT from profiting from the initial capital intensive nature of constructing the storage facility by adding additional storage after GSU's storage needs are met.

295. GSU's control over the construction and equipment ensures that the facility is constructed in the

proper manner in the event GSU exercises its option on the facility.

296. GSU maintains control over third-party use of the storage facility to prevent SGT from retaining any revenue received from third-parties. Revenue received from third-party use of the facility will reduce the Payoff Amount and, ultimately, the transportation fee.

297. GSU's control over the design, construction and operation of the Sabine Spindletop facilities does not require GSU to seek rate base treatment for its payments to SGT.

298. The terms Credit Payment and Non-Credit Payment are contractual terms used to define SGT's use of the proceeds received from GSU.

299. GSU pays SGT a fee for transportation and swing service, and SGT portions out the proceeds between a Credit Payment and a Non-Credit Payment.

***145** 300. All gas companies use a portion of the fee they receive to defray capital costs.

301. It is not unusual to have a minimum take-or-pay obligation in a contract.

302. The fact that the arrangement allows SGT to pay off its capital costs in constructing the project and includes a minimum annual payment does not prevent GSU from seeking to include the SGT payments in the fuel factor.

303. According to Financial Accounting Standards Board (FASB) Statement No. 13, a capital lease is one that, from the standpoint of the lessee, transfers to the lessee substantially all of the benefits and risks incidental to ownership of the leased property. A capital lease is accounted for by the lessee as the acquisition of an asset and the incurring of a liability.

304. GSU categorizes the Spindletop gas storage facility as a capital lease.

305. GSU has never requested that any of its other capital leases, including its nuclear fuel lease, be included in GSU's rate base.

306. Because GSU currently has no investment in the facility and no requirement to invest or to exercise the option, future rate base treatment is uncertain.

307. Merely because GSU accounts for the Sabine Spindletop facility as a capital lease does not require GSU to seek rate base treatment of the costs if the costs otherwise are includible under the Commission's application of the Fuel Rule.

308. If GSU had chosen to own and operate the storage facility itself, then GSU's investment in the facility would have been included in rate base and return would have been included in base rates.

309. GSU did not have the means to build the facility itself due to budgetary constraints.

310. Financial institutions would not provide financing for the project over the 30-year life of the project, but did offer a maximum 10-year period for financing.

310A. The costs of gas storage in the facility operated by Sabine Gas Transportation Company will be included in the cost of fuel at the time the fuel is delivered to Gulf States. This cost is recoverable through the fuel factor, in accordance with Section 23.23(b)(2)(A) and (B) of the Commission's Substantive Rules.

311. GSU's annual total system carrying costs on gas inventory stored in the Spindletop storage facility is approximately $311,200.

312. GSU did not include these carrying costs in its proposed fuel factor calculation filed with its application.

313. GSU's request for reconcilable classification of the gas inventory carrying costs is premature.

314. The carrying costs on gas are base rate costs.

315. GSU treats its inventories of coal and fuel as base rate items.

315A. The carrying costs of gas in the storage facility operated by Sabine Gas Transportation Company will be incurred after the fuel is delivered to Gulf States. This cost is not recoverable through the fuel factor, in accordance with Section 23.23(b)(2)(A) and (B) of the Commission's Substantive Rules.

316. There is no credible evidentiary showing sufficient to support GSU's request for a good cause exception to treat the carrying costs as reconcilable.

***146** 317. It is reasonable to exclude incentive rate expense from the fuel factor calculation.

318. GSU did not include any off-system sales in its proposed fuel year.

319. GSU has made off-system sales for the last 17 years and averaged over 438,000 MWH per year during that period.

320. During the reconciliation period, GSU averaged 303,542 MWH in off-system sales per 12-month period.

321. It is reasonable to include off-system sales adders in the fixed fuel factor calculation as recommended by Calvert.

322. Because the fuel factor calculation involves prospective treatment, there is a plausible policy argument in favor of splitting the adders between the ratepayers and shareholders in order to provide GSU with an incentive to pursue off-system sales above the test year level; otherwise, any off-system sale on a going-forward basis is a net loss unless GSU can recover the variable costs caused by the sale.

323. It is reasonable to split the adders on a prospective basis between the ratepayers and shareholders 75/25 percent in favor of the ratepayers.

324. GSU included $82,862,267 in purchased power costs in its projected fuel year. Of this amount, $62,423,142 constitutes the NISCO-related purchase power expenses, leaving $20,439,125 of non-NISCO purchased power payments in GSU's projected fuel year.

325. The non-NISCO purchased power expenses consist of energy associated with GSU's buyback agreement for Nelson 6 with Sam Rayburn Municipal Power Agency (SRMPA), replacement energy purchases from Entergy, and purchases from the Toledo Bend Dam and various cogeneration sources.

326. General Counsel witness Mr. Neeley did not include any other purchased power in his fuel year estimate other than the NISCO-related purchased power payments.

327. It is reasonable to adjust Mr. Neeley's proposed purchased power cost to account for all other power purchases as proposed by GSU. To make this adjustment, GSU's purchased power estimate for the first six months of **1993** should be annualized and Mr. Neeley's gas usage should be revised accordingly.

328. GSU included 100 percent of its NISCO purchased power payments, or $62,423,142, in its projected fuel year.

329. Based on NISCO payments of $62,423,142 for the fuel year, the amount above avoided cost is $36,890,000 on a total company basis, or $16,603,865 for GSU's Texas jurisdiction.

330. For the reasons stated in Section V.C. of the Report, the portion of GSU's NISCO payments above avoided cost should be excluded from the fixed fuel factor calculation.

331. GSU's projected dispatch of Big Cajun II, Unit 3 will increase because of the relatively low cost of coal there.

332. Calvert's proposed redispatch of Big Cajun II, Unit 3 is inappropriately based on the premise that GSU is entitled to incremental pricing under the JOPOA.

333. It is reasonable to adopt GSU's position that the increase in Big Cajun II, Unit 3 generation will offset spot gas purchases.

***147** 334. The jurisdictional allocator should be calculated using at-plant data, but excluding the effects of company use and reserve station service.

335. In Examiner's Order No. 12, issued May 13, 1992, GSU was ordered to reimburse the cities, on a monthly basis, for 90 percent of their monthly expenses related to this docket.

336. Beaumont and Calvert requested the following actual and estimated expenses relating to their participation in this docket:

Party	Requested[FN*] Actual Expenses	Estimated Future Expenses	Total
Beaumont	$ 375,410.81	$ 49,589.19	$ 425,000.00
Calvert	367,067.12	37,755.88	404,823.00
Total	$ 742,477.93	$ 87,345.07	$ 829,823.00

* The actual expenses are through June 3, **1993** for Beaumont, and through June 10, **1993** for Calvert.

337. GSU took no position regarding the reasonableness of the expenses incurred by the two groups of cities.

338. Except for a few minor disallowances recommended by General Counsel witness Ms. Schultz, no party contested the amount of actual expenses incurred by Beaumont through June 3, **1993**, or by Calvert through June 10, **1993**.

339. Mr. Pous informally audited the invoices and other documentation submitted by the law firm of Butler, Porter, Gay & Day (BPGD), Counsel for Beaumont. He found that the individual charges and rates were reasonable compared to charges for similar services, and that the hours billed were reasonable. The hourly rate for attorneys of BPGD is $150 per hour.

340. There were no errors in the calculation nor any double billing of charges. There were no instances in which any of the charges had been recovered through reimbursement of other expenses or through billings to other entities.

341. The actual amount of rate case expenses incurred by BPGD through June 3, **1993**, is $183,603.22. This amount is comprised of $168,539.25 in fees and $15,063.97 in out-of-pocket expenses. The projected expenses for legal representation through the completion of this docket and subsequent court proceeding are estimated to be $225,000.

342. DUCI, consultant for Beaumont, incurred fee-related charges of $184,456.25 and expenses of $7,351.34 through June 3, **1993**. Therefore, the total level of actual charges through June 3, **1993** for DUCI is $191,807.59. DUCI estimated that the total level of charges for this case would be

$200,000. The estimated amount is comprised of $192,648.66 in fees and $7,351.34 in out-of-pocket expenses and includes the actual fees and expenses incurred through June 3, **1993**.

343. DUCI's overall average hourly labor rate is approximately $95 per hour.

344. Mr. Pous informally audited the invoices and other documentation of DUCI. There were no errors in the calculation nor any double billing of charges, and no instances in which the charges have been recovered through reimbursement of other expenses. There were no expenses or charges that should have been assigned to another jurisdiction.

345. Through June 10, **1993**, the charges for services provided by Jo Campbell, Counsel for Calvert, are $157,350.00. Ms. Campbell's estimate of charges for services for the remainder of this case and any subsequent court proceedings is $30,223.00. Therefore, the total charges, actual and estimated, for legal services rendered on Calvert's behalf are $187,573.00.

***148** 346. Mr. Daniel performed an informal audit of Ms. Campbell's invoices and other supporting documents and verified the accuracy of the charges shown on the invoices. There was no double billing of charges, none of the charges had been recovered from other sources, and none of the charges should have been billed to others.

347. Jo Campbell's $150 per hour fee is reasonable given her prior experience, and compares favorably with hourly fees charged by other attorneys providing similar service.

348. The hourly rates of GDS personnel, Calvert's consultant, range from $28 per hour to $140 per hour. These hourly rates compare favorably with a survey of similar consulting firms in the utility consulting business.

349. Mr. Daniel performed an informal audit of GDS's invoices and supporting documentation. He deleted $360 from GDS' expenses. There was no double billing of charges, none of the charges had been recovered from other sources, and none of the charges should have been billed to others.

350. The total amount of Calvert's requested rate case expenses for legal and consulting services, including additional estimated expenses, is $404,823.00.

351. General Counsel witness Ms. Susan Schultz reviewed the expenses. For professional services, Ms. Schultz required a brief, specific description of the work performed, the number of hours worked, and the hourly billing rate for each individual for which reimbursement was requested. For travel expenses, she required a copy of the original invoice or receipt. For internal expenses such as copying or supplies, she required documentation indicating quantity and the total amount charged.

352. Ms. Schultz verified the arithmetical accuracy of the invoices, receipts, and supporting documentation. She did not find any evidence of double billing of charges. With two limited exceptions, she found the requested actual expenses and individual hourly billing rates to be reasonable.

353. Ms. Schultz' recommended actual rate case expenses through June 3, **1993** for Beaumont, and through June 10, **1993** for Calvert are as follows:

Party	Recommended Actual Expenses
Beaumont	
Legal	$ 183,603.22
DUCI	191,807.59
Total	$ 375,410.81
Calvert	
Legal	$ 157,350.00

GDS	209,717.12
Total	$ 367,067.12 =
Grand Total	$ 742,477.93

354. Except for a $9.06 disallowance for Beaumont and a $360 voluntary reduction by Calvert, no party contested the reasonableness of Beaumont's actual incurred expenses and fees through June 3, **1993**, or Calvert's actual incurred expenses and fees through June 10, **1993**.

355. Beaumont's and Calvert's actual incurred rate case expenses as recommended by Ms. Schultz should be approved. The cities' estimates for additional rate case expenses are reasonable. It is reasonable to require GSU to compensate the cities for rate case expenses incurred by them up to the amount of their estimated expenses.

356. In Docket No. 9030, the Commission found that the utility's expenses incurred as a result of processing a fuel reconciliation proceeding were not fuel-related costs. *Petition of General Counsel For a Fuel Reconciliation For Southwestern Public Service Company*, Docket No. 9030, 17 P.U.C. BULL. 395, 460-461, 471 (June 3, 1991).

***149** 357. In Docket No. 10035, the Commission approved a stipulation in a fuel reconciliation proceeding which included the intervening city's rate case expenses as fuel-related costs. *Application of West Texas Utilities Company to Reconcile Fuel Costs and For Authority to Change Fixed Fuel Factors*, Docket No. 10035, 17 P.U.C. BULL. 545, (Sept. 30, 1991) (mem.).

358. Based on the Commission's decision in Docket No. 9030, GSU's request to recover the cities' reimbursed litigation expenses through the fixed fuel factor in this proceeding should be denied.

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.

360. All fuel-related affiliate expenses considered in this case, with the exception of the NISCO costs above GSU's avoided cost, were reasonable and necessary. The prices the non-NISCO affiliates charged GSU were no higher than prices charged by the affiliate to its other affiliates or divisions or to unaffiliated person or corporations for the same item or class of items.

B. *Conclusions of Law*

1. GSU is a public utility as defined in Public Utility Regulatory Act (PURA), Tex. Rev. Civ. Stat. Ann. , art. 1446c (Vernon Supp. **1993**) § 3.

2. The Commission has jurisdiction in this proceeding pursuant to PURA §§ 16, 17(e) and 43(g).

3. GSU gave notice of this proceeding as required by P.U.C. PROC. R. 21.22(b)(4).

4. An expense is not an allowable reconcilable fuel cost to the extent it resulted from a utility's imprudence.

5. Prudence is the exercise of that judgment and the choosing of one of that select range of options which a reasonable utility manager would exercise or choose in the same or similar circumstances given the information or alternatives available at the point in time such judgment is exercised or option is chosen.

6. There may be more than one prudent option within the range available to a utility in any given context. Any choice within the select range of reasonable options is prudent, and the Commission should not substitute its judgment for that of the utility. The reasonableness of an action or decision

must be judged in light of the circumstances, information, and available options existing at the time, without benefit of hindsight.

7. An isolated error or failure to identify or correct an isolated problem can constitute imprudence. Whether it does or not depends upon whether the utility's conduct accords with the prudence standard.

8. *The doctrine of collateral estoppel applies to relitigation of ultimate issues;* it does not bar relitigation merely because the outcome of two cases may appear to be inconsistent. *Tarter v. Metropolitan Savings & Loan Association*, 744 S.W.2d 928-929 (Tex. 1988).

9. The first clause of PURA § 3(i)(6) requires a finding of the actual exercise of substantial influence or control over the public utility by the alleged affiliate. The third clause of PURA § 3(i)(6) requires a finding that the person or corporation is under common control with a public utility, such control being the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of another. Unlike the first clause, the third clause does not require actual exercise of substantial influence or control.

***150** 10. GSU and NISCO are affiliates under PURA § 3(i)(6).

11. Under PURA § 41(c)(1) and *Rio Grande*, the appropriate perspective is from the perspective of the buyer of the affiliate service, in this case GSU and other potential buyers of the service provided by NISCO.

12. Because there are no other buyers of the service provided by NISCO, is appropriate to apply a market test to determine the reasonableness of the NISCO transaction under the first requirement of the *Rio Grande* test.

13. The intent in structuring the NISCO venture is irrelevant to whether the effect of the NISCO agreement results in GSU having the power to direct or cause the direction of the management and policies of NISCO, or vice versa.

14. *GSU failed to show that the affiliate expenses in the NISCO transaction are just and reasonable* under PURA § 41(c)(1) and P.U.C. SUBST. R. 23.23(b)(2)(H)(iv).

15. Approval of GSU's request to classify carrying costs as reconcilable will preclude the Commission in a subsequent fuel reconciliation case from deciding that the carrying costs should be treated in another manner.

16. The Commission has the discretion to allocate profits from off-system sales if the ordered allocation is supported by the facts and policy considerations in the record.

17. The intent of the Fuel Rule is that the fuel factor should be developed using information relating to the period in which the fuel factor is expected to be in effect - the fuel year. P.U.C. SUBST. R. 23.23 (b)(2)(C).

18. All known or reasonably predictable fuel costs, whether fixed or variable, and not specifically excepted by the Fuel Rule, should be included in the fixed fuel factor. *Application of Texas Utilities Electric Co. for Authority to Change Rates*, Docket No. 9300, Finding of Fact No. 223, 7 P.U.C. BULL. 2057, 2777 (September 27, 1991).

19. A fuel reconciliation proceeding is a ratemaking proceeding. *Application of El Paso Electric Company for Authority to Change Rates*, Docket No. 9165, 16 P.U.C. BULL. 605, 772, 1029 (August 22, 1990).

20. The cities are entitled to reimbursement of reasonable expenses under PURA § 24.

21. $116,740,170 *of GSU's requested fuel cost balance should be disallowed because* GSU failed to

meet its burden of proof under PURA §§ 39(a) and 41(c)(1), P.U.C. SUBST. R. 2323(b)(2)(H)(i)-(iv), and the Texas Supreme Court test regarding those costs.

22. Except as indicated otherwise in the Examiner's Report, GSU met its burden of proof under PURA §§ 39(a) and 41(c)(1) and P.U.C. SUBST. R. 23.23(b)(2)(H)(i)-(iv) regarding costs it requested be treated as allowable reconcilable fuel expense for the reconciliation period.

ORDER ON REHEARING

On July 6, **1993**, the Public Utility Commission of Texas (Commission) signed a final order in this docket. Motions for rehearing and replies to those motions were timely filed by Gulf States Utilities Company (GSU), Texas Industrial Energy Consumers (TIEC), Beaumont et al. (Beaumont), Calvert, et al. (Calvert), the Office of Public Utility Counsel (OPC) and the General Counsel. On August 18, **1993**, in open meeting at its offices in Austin, Texas, the Commission considered the motions for rehearing and replies to those motions. After deliberation of the issues raised in the motions for rehearing and the replies, the Commission hereby grants rehearing on the following points and orders the following relief:

***151** Findings of Fact Nos. 22, 23, 33, 152, 209, 323, 332, and 333 are *AMENDED* as follows:

22. On November 8, 1990, GSU filed an amended counterclaim against Cajun Electric in U.S. District Court, Middle District of Louisiana, alleging that Cajun Electric violated its fiduciary duties as agent to GSU, and had breached the terms of the JOPOA, by not allowing GSU to benefit from the lower-priced incremental coal. The Court's interpretation of JOPOA will affect the regulatory treatment to be accorded the reconciliation of coal costs incurred by GSU at Big Cajun II, Unit 3 during the reconciliation period at issue in this docket. [21] 23. It is appropriate to defer ruling at this time on all matters affecting the litigation between GSU and Cajun Electric Power or on any regulatory issues that might arise from matters emanating from that litigation until such time as the federal litigation is concluded, whether by order of the Court, by settlement of the parties, or other manner. GSU should be required to report to the Commission the resolution of the dispute with Cajun Electric, including the general terms of the resolution, the amount, if any, that will be paid to GSU, and the costs of the litigation. The regulatory treatment of any recovery by GSU related to the incremental coal issue shall be determined together with all other relevant issues emanating from the litigation after it is concluded. 33. GSU is requesting that the Commission recognize as fuel costs $185,094,913 in payments to NISCO during the reconciliation period. This amount is comprised of $77,448,704 in payments equal to GSU's avoided cost and an additional $107,646,209 in payments in excess of GSU's avoided cost. 152. The 11-day delay in the critical path resulted from imprudence. It was GSU's responsibility to ensure that Cooper Industries became familiar with GSU's procedural requirements and organized its work properly to conduct the work in compliance with the agreed upon schedule. The resulting increase in fuel costs of $1,584,012 on a total company basis should be disallowed. 209. The failure to use correct o-rings was imprudent. GSU has the responsibility to have adequate procedures and controls in place and to take steps to see that its contract employees comply with them to prevent the installation of incorrect parts and material. GSU did not do so. The resulting increase in fuel cost of $400,330 on a total company basis should be disallowed. 323. Beginning with the effective date of the fixed fuel factor approved in this proceeding, it is reasonable to split the adders between the ratepayers and shareholders 75/25 percent in favor of the ratepayers. 332. Dispatch of generation from Big Cajun II, Unit 3 will be increased and these increases will be offset by reductions in generation at the Nelson 6 unit for the calculation of the fuel factor. 333. The resulting increase in gas generation caused by the reduction in generation at Nelson 6 will occur at Willow Glen 5 generating unit for the calculation of the fuel factor.

***152** The Commission further issues the following Order:

1. GSU *SHALL* file six copies of its tariff, revised in accordance with this Order on Rehearing, with the Commission filing clerk and one copy with each party of record within 20 days of the date of this Order on Rehearing. The revised tariff shall be reviewed in accordance with the procedures set forth in the July 6, **1993**, Order. 2. In all other respects, the requests for relief contained in the motions for

rehearing and the replies to those motions are hereby *DENIED* for lack of merit. 3. This Order on Rehearing hereby *INCORPORATES* by reference as if set out in full all aspects of the Order of July 6, **1993**, in this docket, including all schedules and all findings of fact and conclusions of law made by the Commission in that Order, except as expressly amended by this Order on Rehearing.

CONCURRENCE AND DISSENT

I concur with the Commission's Order on Rehearing except on the issue raised in my Concurrence and Dissent from the July 6, **1993**, Order. I continue to dissent on that issue.

SIGNED AT AUSTIN, TEXAS this 19th day of August **1993**.

CONCURRENCE AND DISSENT

I concur with the Commission's Order on Rehearing except on the issue raised in my Concurrence and Dissent from the July 6, **1993**, Order. I continue to dissent on that issue.

SIGNED AT AUSTIN, TEXAS this 19th day of August **1993**.

CONCURRENCE AND DISSENT

I concur with the Commission's Order on Rehearing except with respect to the motions for rehearing granted by the majority, and except with respect to the issues raised in my Concurrence and Dissent from the July 6, **1993**, Order. I continue to dissent on those issues, and I would further deny all motions for rehearing.

SIGNED AT AUSTIN, TEXAS this 19th day of August **1993**.

FOOTNOTES

FN1 *Inquiry of the Public Utility Commission of Texas into the Prudence and Efficiency of the Planning and Management of the Construction of the South Texas Nuclear Project,* Docket No. 6668, 16 P.U.C. BULL. 183, 483 (June 20, 1990).

FN2 Docket No. 6668, 16 P.U.C. BULL. at 483.

FN3 *Application of Houston Lighting and Power Company for Reconciliation of Fuel Costs Through March 31, 1990,* Docket No. 10092, 17 P.U.C. BULL. 3427, 3436, 3495 (February 18, 1992).

FN4 GSU would apparently agree with the ALJ on this point. GSU Ex. 77A at 22.

FN5 Calvert Ex. 23B, Sch. EP-1.

FN6 Calvert Ex. 23B, Sch. EP-2.

FN7 Calvert Ex. 23B, Sch. EP-3.

FN8 Cajun Electric considered itself and GSU to be competitors in the off-system sales market and apparently refused to allow GSU to review unedited versions of the contracts.

Tr. 2121.

FN9 Cajun Electric had filed the original complaint against GSU in June 1989 which requested, among other things, recovery of Cajun Electric's $1.6 billion investment in River Bend. Calvert Ex. 23B at 34.

FN10 *Accord*; *Application of West Texas Utilities Company to Reconcile Fuel Costs and for Authority to Change Fixed Fuel Factors*, Docket No. 10035, Finding of Fact No. 23, 17 P.U.C. BULL. 545 (September 20, 1991) (mem.).

FN11 Mr. Griffith's deposition testimony sheds some unfavorable light on his prefiled direct testimony and calls into question the credibility of his prefiled direct testimony. Beaumont Ex. 35 at 51.

FN12 *See*, e.g., Oral Ruling in Docket No. 11292, *Application of Entergy Corporation and Gulf States Utilities Company for Sale, Transfer, or Merger*, (August 17, 1992), in which Judge Sanford denied the City of New Orleans' motion to intervene. Judge Sanford's ruling was upheld by Commission order entered September 11, 1992.

FN13 *Petition of the General Counsel to Inquire into the Reasonableness of the Rates and Services of Southwest Texas Telephone Company*, Docket No. 9983, 18 P.U.C. BULL. 803, 858 (Aug. 14, 1992); *Application of Houston Lighting and Power Company for Authority to Change Rates*, Docket No. 9850, 17 P.U.C. BULL. 3063, 3176 (Oct. 23, 1991); *Inquiry of the General Counsel into the Reasonableness of the Rates and Services of Southwestern Bell Telephone Company*, Docket Nos. 8585 and 8218, 17 P.U.C. BULL. 1045, 1853-1854 (Jan. 10, 1991).

FN14 See OPC Ex. 50 at 20-21; Beaumont Ex. 16 at 24-31; General Counsel Ex. 11 at Sch. RRR-2; OPC Brief at Appendix A.

FN15 P.U.C. SUBST. R. 23.23(b)(4).

FN16 Tr. 1679-1680.

FN17 The critical path is the minimum amount of time necessary to complete a set of events in a project.

FN18 The results of the Doble test were apparently not supplied in discovery, although GSU and Calvert disagree as to whether they were ever requested.

FN19 Calvert Ex. 23B, Sch. EP-5.

FN20 Docket No. 9300, 17 P.U.C. BULL. at 2626, 2899 (Finding of Fact No. 394).

FN21 *See* TIEC Ex. 1 for a schematic drawing of the Sabine Station pipeline interconnections.

FN22 GSU's main problem is with daily swing which is the difference between high demand periods and low demand periods. The fuel requirement increases as the demand for energy increases. Tr. 513.

FN23 As correctly noted by GSU in reply brief, OPC and TIEC, although proposing various standards for determining whether a cost is properly reconcilable in prefiled direct testimony, did not brief those standards and, consequently, have apparently abandoned those standards.

FN24 Given the ALJ's recommended treatment of the historical adders as reconcilable, she doubts GSU would continue to agree to share the adders prospectively.

FN25 If the Commission adopts the General Counsel's recommended fuel year, Mr. Norwood's recommended adjustment for off-system sales would not change because he used an estimate of what an annual off-system sales profit should be going forward, which is not based on any specific 12-month period. Tr. 1635.

FN26 *See Application of West Texas Utilities Company to Reconcile Fuel Costs and for Authority to Increase Fixed Fuel Factors*, Docket No. 10035, Examiner's Order No. 6 (May 1, 1991). This docket was ultimately settled by the parties.

FN27 *Application of Houston Lighting & Power Company for Authority to Change Rates* and *Application of Houston Lighting & Power Company for a Final Reconciliation of Fuel Costs through September 30, 1988*, Docket Nos. 8425 and 8431, 16 P.U.C. BULL. 2199, 2227 (June 20, 1990). The issue of reimbursement was ultimately resolved by agreement of the parties.

FN28 The ALJ had to calculate the estimated expenses for Beaumont by simple subtraction of the actual incurred expenses through October 1992 from the total requested expenses, actual and estimated.

FN29 The General Counsel appears to have changed course in its brief. General Counsel Brief at 45-46.

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19 Tex. P.U.C. Bull. 1401, 1993 WL 655241 (Tex.P.U.C.)

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