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SOAH DOCKET NO. 473-22-04394
PUC DOCKET NO. 53719

APPLICATION OF ENTERGY TEXAS, INC. FOR AUTHORITY TO CHANGE RATES	**§ § §**	**STATE OFFICE OF ADMINISTRATIVE HEARINGS**

RESPONSE OF ENTERGY TEXAS, INC.
TO TIEC'S SEVENTH REQUEST FOR INFORMATION:
TIEC 7:1

Entergy Texas, Inc. ("ETI" or the "Company") files its Response to TIEC's Seventh Request for Information. The response to such request is attached and is numbered as in the request. An additional copy is available for inspection at the Company's office in Austin, Texas.

ETI believes the foregoing response is correct and complete as of the time of the response, but the Company will supplement, correct or complete the response if it becomes aware that the response is no longer true and complete, and the circumstance is such that failure to amend the answer is in substance misleading. The parties may treat this response as if it were filed under oath.

Respectfully submitted,

Kristen F. Yates

Kristen Yates
ENTERGY SERVICES, LLC
919 Congress Avenue, Suite 701
Austin, Texas 78701
Office: (512) 487-3962
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Attachments: **TIEC 7:1**

CERTIFICATE OF SERVICE

I certify that a copy of the foregoing Response of Entergy Texas, Inc. to TIEC's Seventh Request for Information has been sent by either hand delivery, electronic delivery, facsimile, overnight delivery, or U.S. Mail to the party that initiated this request in this docket on this the 7th day of November 2022.

Kristen F. Yates

Kristen Yates

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc.	Prepared By: Josh Paternostro, Matthew Shoemake
to the Seventh Set of Data Requests	Sponsoring Witnesses: Allison P. Lofton, Richard E. Lain
of Requesting Party: Texas Industrial Energy Consumers	Beginning Sequence No. PI2049
	Ending Sequence No. PI2244

Question No.: TIEC 7-1 Part No.: Addendum:

Question:

Referring to "Pages 5-49" of Schedule P, with respect to miscellaneous gross receipts taxes:

a. Please confirm that these taxes are shown in rows 2001 and 2002.

b. Please confirm that the allocation factor RSRRTOA-RO is based on total retail sales revenue.

c. Please explain how allocating these taxes on total retail sales revenue is consistent with cost-causation, and provide any supporting documentation.

Response:

a. Confirm.

b. Confirm.

c. Entergy Texas Inc's ("ETI") proposal is based on the decisions of the Public Utility Commission of Texas ("PUCT" or "the Commission") in Docket No. 16075 and ETI's most recent fully-litigated rate case, Docket No. 39896,[1] in

[1] *Application of Entergy Gulf States, Inc. for Approval of its Transition to Competition Plan and the Tariffs Implementing the Plan, and for the Authority to Reconcile Fuel Costs, to Set Revised Fuel Factors, and to Recover a Surcharge for Under-Recovered Fuel Costs,* Docket No. 16705, Second Order on Rehearing, Finding of Fact No. 225 (Oct. 14, 1998) and *Application of Entergy Texas, Inc. for Authority to Change Rates, Reconcile Fuel Costs, and Obtain Deferred Accounting Treatment,* Docket No. 39896, Order on Rehearing, Finding of Fact No. 182 (Nov. 11, 2012). See also, *Application of Entergy Texas, Inc. for Authority to Change Rates, Reconcile Fuel Costs, and Obtain Deferred Accounting Treatment*, Docket No. 39896, Revised Schedules for Entergy Texas Reflecting Changes Based on Number-running (Aug. 28, 2012).

which the Commission found the allocation of ETI's miscellaneous gross receipts taxes should be based on the ratio of total customer class revenues to total revenues. In its most recent rate applications in which settlement agreements were reached with Staff and the parties (Docket Nos. 41791 and 48371), ETI also proposed the allocation of miscellaneous gross receipts taxes based on the ratio of total customer class revenues to total revenues consistent with the Commission's precedent that applies to the Company. The Commission's findings in these base rate proceedings can be found on the PUCT Interchange. For the Commission's Second Order on Rehearing and Order on Rehearing in Docket No. 16075, please see the attachment (TP-53719-00TIE007-X001).

PUC DOCKET NO. 16705
SOAH DOCKET NO. 473-96-2285

APPLICATION OF ENTERGY TEXAS FOR APPROVAL OF ITS TRANSITION TO COMPETITION PLAN AND THE TARIFFS IMPLEMENTING THE PLAN, AND FOR THE AUTHORITY TO RECONCILE FUEL COSTS, TO SET REVISED FUEL FACTORS, AND TO RECOVER A SURCHARGE FOR UNDER-RECOVERED FUEL COSTS	§ § § § § § § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

SECOND ORDER ON REHEARING

This Second Order on Rehearing (Order) addresses the application filed by Entergy Gulf States, Inc. (EGS or the Company) on November 27, 1996, in accordance with Paragraph 9b of the Stipulation and Agreement approved by the Commission in Docket No. 11292.[1] Through this Order, the Commission adopts in part and modifies in part the Proposal for Decision (PFD) as corrected and the Supplemental Proposal for Decision (SPFD) issued by the State Office of Administrative Hearings (SOAH) Administrative Law Judges (ALJs) in late March 1998.[2]

I. Introduction

The SOAH ALJs conducted separate evidentiary hearings on the four component parts of this docket: fuel, revenue requirement, cost allocation/rate design, and competitive issues. After completion of the hearings and review of the record evidence, the ALJs recommended that the Commission order EGS to reduce its current Texas retail base rates by $137 million, which

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[1] *Application of Entergy Corporation and Gulf States Utilities Company for Sale, Transfer or Merger,* Docket No. 11292, 19 P.U.C. BULL. 2040, 2041 (Ordering Paragraph 5) (Dec. 29, 1993).

[2] The ALJs issued the PFD on March 25, 1998, as revised by clarifications, revised text, and revised schedules filed on June 4, 12, and 16, 1998. The ALJs issued the SPFD, which addresses supplemental fuel-related issues, on March 27, 1998. The Commission considered the matters addressed in this Order at its open meetings convened on June 30, July 8 through 10, July 13, July 16, and July 22, 1998. The Commission issued its "final" order in this docket on July 22, 1998. The Commission considered motions for rehearing at its open meetings convened on August 26, and October 8, 1998. A more detailed procedural history of this case is contained in Attachment A to the PFD and the Findings of Fact (FoF) and Conclusions of Law (CoL), as modified, contained in this Order.

represents a 29% reduction from current base rates. The rationale for this recommended reduction is set forth in detail in the PFD and SPFD which, together, total over 800 pages.

In this Order, the Commission directs EGS to reduce its Texas retail base rates in conformance with the attached schedules (approximately $111 million, or $26 million less than the reduction recommended by the ALJs). This base rate reduction, and the Commission's rationale for modifying portions of the PFD and SPFD, are explained in detail in the Discussion section of this Order. In this Introduction, the Commission focuses primarily on the three most contentious issues in this docket: (1) treatment of EGS' claimed affiliate expenses; (2) the treatment of EGS' "excess costs over market" (referred to either as "ECOM" or "potentially stranded investment"); and (3) interruptible service.

A. <u>Affiliate Expenses</u>

The ALJs concluded in the PFD that EGS failed to meet its statutory burden of proof to justify recovery of approximately $86 million in Texas retail affiliate expenses. The ALJs therefore recommended that the Commission disallow all of these claimed costs.[3] This $86 million in recommended disallowed expenses is comprised of $49 million billed to EGS by its corporate service affiliate, Entergy Services, Inc. (ESI), or allocated to EGS by its nuclear service affiliate, Entergy Operations, Inc. (EOI), plus an additional $37 million direct-billed to EGS by EOI.[4] In the alternative to a full disallowance, the ALJs recommended that the Commission could potentially justify allowing EGS to recover the direct-billed EOI affiliate expenses ($37 million), but that the record clearly required disallowance of the $49 million in ESI and EOI allocated expenses. (To avoid confusion, this Order refers to the ESI billed and EOI *allocated* expenses as the $49 million in disallowed "ESI" expenses; the $37 million in EOI *direct billed* expenses are referred to as the "EOI" expenses.) In this Order, the Commission adopts the ALJs' alternative recommendation and thereby allows the EOI affiliate expenses, but disallows the ESI expenses.

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[3] For convenience, this Introduction refers only to the Texas retail affiliate expenses claimed by EGS. The Company's application and the PFD actually refer primarily to "system-wide" affiliate expenses in the range of $200 million. The system-wide expenses include affiliate expenses allocable to EGS' services in Louisiana, services in the Texas wholesale market, and services in the Texas retail market.

[4] The complexity of the affiliate transactions affecting EGS (previously Gulf States Utilities, Inc. (GSU)) significantly increased when Entergy Corporation purchased GSU in 1993, thereby creating EGS.

EGS poses 17 points of error challenging the Commission's decision to disallow the $49 million in ESI expenses. EGS asserts that the Commission's ruling "rejects prior precedent, and replaces it with a new standard of proof for recovery of affiliate costs without giving EGS a meaningful opportunity to comply with the new standard."[5] As summarized in this Introduction and as discussed in more detail in the Discussion below, each of these 17 points of error is wrong, and all are hereby denied.

The Commission's reason for disallowing the $49 million in ESI expenses has nothing to do with a purported change in Commission standards or a lack of due process--nothing changed and the Commission afforded EGS ample due process. First, the heightened scrutiny applicable to affiliate expenses, which is a *statutory* requirement, has been explicit in Commission precedent for over 17 years. The Commission announced as early as 1981 that: "Affiliate transactions have been receiving greater attention in recent cases than they have in the past."[6] Second, the Commission provided EGS with extraordinary due process in this docket. While utilities typically have one opportunity to file and present a case supporting cost recovery, EGS had three. Despite three distinct opportunities, the Company nevertheless failed to muster the evidence necessary to prove up recovery of the disallowed $49 million. In the end, EGS left the Commission with no other options. The Company simply, but clearly and repeatedly, failed to meet its statutory burden of proof to justify recovery of the disallowed affiliate expenses.

1. Burden of Proof for Recovery of Affiliate Expenses.

The burden of proof borne by the utility with regard to affiliate expenses is a *statutory* requirement that, in its current form, has been in place since at least 1983.[7] This burden is particularly heavy because the Public Utility Regulatory Act (PURA)[8] expressly precludes the Commission from allowing a utility to recover any payment to an affiliate unless the Commission finds the payment is "reasonable and necessary for each item or class of items as

[5] EGS' Second Motion for Rehearing at 61 (Sept. 24, 1998).

[6] *Application of Central Telephone Company of Texas for a Rate Increase Within Harris, Montgomery, Coryell and Burnet Counties,* Docket No. 3510, 7 P.U.C. BULL. 185, 214 (April 20, 1981).

[7] *See* Act of May 26, 1983, 68th Leg., 2d. R.S., ch. 274, 1983 TEX. GEN. LAWS 1258 (current version at TEX. UTIL. CODE ANN. § 36.058 (Vernon 1998)).

[8] TEX. UTIL. CODE ANN. §§ 11.001 - 63.063 (Vernon 1998).

determined by the commission."[9] Further, PURA dictates that a finding by the Commission in favor of a claimed affiliate expense must include:

> (1) a specific finding of the reasonableness and necessity of each item or class of items allowed; and
>
> (2) a finding that the price to the electric utility is not higher than the prices charged by the supplying affiliate to its other affiliates or divisions or to a nonaffiliated person for the same item or class of items.[10]

In this docket, the Commission is precluded from making any of the required findings with regard to the ESI expenses because of EGS' complete failure to present an adequate case. EGS submitted reams of affiliate expense data, but that data is a jumble of disconnected and unsupported transactions. As the ALJs concluded, and as the Commission confirms:

> Because [EGS' scope statements] are not arranged by class and no underlying evidence is included to support the reasonableness or necessity of the items by class, the only way for the Commission to make an independent evaluation of these costs is by looking at each item. Such [a] task would be daunting.[629] No other evidence exists in the record to support findings for each item, and EGS witnesses testify only as to *total* costs.
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> [629] Even [EGS witness] Mr. Uffelman, who spent many hours and charged EGS thousands of dollars, said in his report, "Due to the large number of SRs and Work Codes . . . there was no practical way in which to examine all of the transactions." EGS Ex. 93, Ex. BLU-3 at 9.[11]

The Company--not the Commission, not the ALJs, and not the intervenors--is required to prove that its claimed expenses meet the high statutory burden of proof set forth in PURA § 36.058. It is the Company's duty to put on a coherent case before expecting the Commission to find that claimed expenses are reasonable and necessary in accordance with PURA.

2. The Commission Afforded EGS Extraordinarily Generous Due Process Rights.

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[9] PURA § 36.058(b).

[10] PURA § 36.058(c).

[11] PFD at 255 (emphasis in original).

The Commission went to extraordinary lengths to ensure that the record is sufficient to justify *either* allowance *or* disallowance of all or some portion of the disputed affiliate expenses. EGS did not rise to the evidentiary opportunities provided, and therefore cannot seriously complain that its rights have been violated, or that the Commission must allow it to recover expenses that clearly have *not* been shown to be reasonable and necessary.

The First Opportunity--EGS' direct case. EGS initiated this docket in November 1996 by filing its "rate filing package" (RFP). The RFP included lengthy testimony and exhibits addressing affiliate expenses, including statements by Company witnesses acknowledging the statutory and case law standards. In discovery disputes early in the docket, however, a controversy arose over EGS' affiliate expense burden. Upon appeal of these discovery disputes to the Commission in February 1997, the Commission ruled, over EGS' protests, that the Company must provide extensive affiliate information to the intervenors. The Commission concluded that if it did not order EGS to provide more extensive and coherent discovery on affiliate expenses, the limited information that EGS wanted to provide "will not be sufficient for the parties, the ALJs, and the Commission to undertake a thorough and adequate analysis of affiliate transactions as required by § 2.208(b) of PURA95 [now § 36.058 of PURA]."[12]

Subsequently, in a supplemental preliminary order issued on March 7, 1997, the Commission placed EGS on even greater notice that the Company must address detailed affiliate expense questions. Among other things, the Commission directed the parties to address whether EGS had taken advantage of all reasonable opportunities to lower costs by "outsourcing" services, or otherwise acquiring services at market-based prices.[13]

The Second Opportunity--EGS' supplemental direct case. Based in part on the supplemental preliminary order, the SOAH ALJs extended the procedural schedule by 60 days and ordered EGS to file supplemental direct testimony regarding, among other items, the pricing and accounting methods used by EGS in transactions with other entities. EGS filed supplemental direct testimony on April 4, 1997, but its witnesses assigned to address the affiliate

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[12] Order on Appeal of Order No. 17 at 2 (Feb. 26, 1997).

[13] Supplemental Preliminary Order at 5 (March 7, 1997).

expense issues discussed, primarily, how EGS accounts for costs from affiliates, rather than how the affiliate expenses satisfy the strict requirements of PURA § 36.058.[14]

The Third Opportunity--EGS' case on remand of Order No. 124. The ALJ assigned to the revenue requirement phase (which addressed affiliate expense issues) admitted EGS' direct and supplemental direct testimony into evidence on August 4, 1997, and allowed cross-examination of EGS' witnesses. At the close of the Company's direct case, and before submitting its own case into evidence, the Commission's General Counsel moved for summary decision on the affiliate expense issue, arguing that EGS failed to provide the minimum information necessary to meet its statutory burden of proof. After considering responses, the ALJ issued her Order No. 124, which granted General Counsel's motion and certified the ruling to the Commission for review.

By granting General Counsel's motion, the ALJ disallowed all but $9.6 million (system-wide) in claimed affiliate expenses. On a Texas retail basis, this resulted in the recommended $86 million disallowance. Among other things, the ALJ noted in Order No. 124 that one of the Company's own witnesses on affiliate expense issues testified that a utility has a higher burden of proof with regard to affiliate expenses than any other costs, and that the Texas statute reverses a presumption that historical test year expenses are prudent and reasonable.[15] That same witness testified that, due to the large number of Service Requests and Work Codes utilized by EGS and its affiliates, "there was no practical way in which to examine all of the [affiliate] transactions."[16]

EGS argued in response to Order No. 124 that the ALJ had misapplied the statutory standard. EGS insisted that it had met its burden of proof, despite statements by its witnesses during cross examination that they had not testified to the reasonableness of the affiliate costs on either an item by item or class of item basis. Nevertheless, EGS asserted that (1) "[a]ll required

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[14] Despite the Commission's early statements on the scope of the affiliate expense issues, EGS again tried to limit the scope of affiliate information that it intended to provide to the intervenors. On appeal of subsequent discovery rulings, the Commission reiterated: "Allocations between affiliates are a critical issue in this case." . . . "In order to ensure that EGS is not charged a higher rate than affiliates, it is necessary to look at final billing records, even if they are rebilled through an intermediate billing entity." Order on Appeal of Order Nos. 46, 49 and 50 at 2 and 3, respectively (April 30, 1997).

[15] Order No. 124 at 27 (Oct. 14, 1997) (citing to the transcript cross-examination of EGS witness Uffelman).

[16] *Id.* at 29 (citing to Mr. Uffelman's Exh. BLU-3 at 9).

evidence is in the record": (2) "[t]he parties have the data available in electronic format and can sort it in any manner they wish"; and (3) during the hearing, an EGS witness "offered to re-sort the existing evidentiary data in whatever manner the ALJ desired in order to facilitate her review . . . ."[17]

Based on EGS' unequivocal assertion that "all required evidence is in the record," and its suggestion that it could re-sort the evidentiary data, the Commission remanded Order No. 124 to SOAH and thereby provided EGS with a third opportunity to prove up its affiliate expenses. The Commission stated that this remand would "allow EGS a final opportunity to reorganize and present its affiliate expense-related evidence to the ALJ in a clear and readily understandable format."[18] However, because EGS unequivocally stated that "all required evidence is in the record," the Commission ruled that the remand

> is not to be used to file new data, interpretations, or argument. . . . The Company should be limited to reformulating its information already provided in pleadings and discovery, by class of item as directed by the ALJ. As this ruling is providing a final opportunity to EGS to attempt to justify its affiliate expenses, it is incumbent upon the Company to present its revised filing in a manner that will not require additional discovery from the parties.[19]

On remand, the ALJ reconfirmed her original recommendation for a full disallowance but, for the first time, recommended *in the alternative* that the Commission could possibly grant recovery of approximately $37 million in EOI direct-billed (but not allocated) affiliate expenses. Through this Order, the Commission adopts the ALJ's alternative recommendation.

Commission Action on Rehearing. EGS, in its motion for rehearing, attempts to shift responsibility for its inadequate affiliate expense presentation to the Commission. Now EGS argues that it meant to circumscribe its unequivocal plea that "all required evidence is in the record." EGS argues that it should have been allowed to introduce new evidence on remand. EGS essentially argues that, until rehearing, it did not understand the heavy statutory burden of proof that applies to affiliate expenses. The Company did not understand despite its own

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[17] Brief of Entergy Gulf States, Inc. in Opposition to Order No. 124 at 8-9 (Oct. 27, 1997).

[18] Order Denying Motion to Consolidate and Addressing Affiliate Expense Issues Certified in Order No. 124 at 3 (November 6, 1997).

[19] *Id.*

witness' statements and the Commission's attempts through the discovery orders and the supplemental preliminary order to point EGS to the long-standing statutory standard. EGS had every opportunity to meet the affiliate expense standard, if not through its initial direct testimony, then through its supplemental direct testimony and its "re-sorting" of the evidence on remand of Order No. 124. Further, as addressed in more detail in the Discussion below, EGS' statements regarding "all necessary evidence is in the record" applied not only to allocated costs, but also to *each* cost on an item-by-item basis.

In this Order, the Commission adheres to its original decision to accept the ALJs' alternative recommendation, and thereby allow EGS to recover $37 million of its EOI direct-billed affiliate expenses from its Texas retail customers. The Commission does so based on consideration of all rate treatments ordered in this docket, including the substantial decrease in EGS' base rates. The Commission is mindful of the paucity of EGS' presentation, even with regard to the EOI direct-billed expenses. However, the Commission rules that the EOI direct-billed expenses are marginally proved up through the record evidence in this docket. In future rate cases, however, the Commission expects a much more coherent and solid affiliate expense presentation if the Company expects to recover any of its claimed affiliate expenses.

B. ECOM

In addition to traditional rate-related issues, EGS' November 27, 1996 RFP requested approval of a *Transition to Competition Plan* (the Plan). Through the Plan, EGS proposed to recover its investment in the River Bend Nuclear Generating Station (River Bend) over a seven-year transition period.[20] Under the Plan, EGS proposed to provide its customers with the opportunity for a competitive retail market at the end of that transition period.

The traditional rate-related and fuel issues raised in the application are complex but familiar to the Commission. The transition-related issues reflected in the Plan, however, presented the Commission with its first opportunity to address a transition plan filed and carried to hearing by an electric utility. The preliminary order issued in this docket on January 24, 1997,

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[20] Absent this seven-year transition period, the cost of River Bend would be recovered over the expected 40-year life of the facility which, at present, extends into 2025.

therefore, focused primarily on the unique transition components and anticipated effects and benefits of the Plan.

PURA recognizes that the opening of the wholesale electric market is in the public interest and that the Commission will need to implement new rules, policies, and principles to protect the public interest in a more competitive marketplace. Section 31.003 of PURA recognizes that wholesale competition can impact customers in both the competitive and noncompetitive markets. As a result of these changes in the law and in the industry, electric utilities should no longer be adding new generation facilities to rate base; new generation resources will instead come from the competitive wholesale market. Increased competition is also placing pressure on utilities to reduce expenses and become more efficient. As a result of these and other factors, electric utilities are now in a period of declining costs, but recovery of utility sunk costs is riskier than in a non-competitive environment. The Commission must therefore strike a balance between reducing the risk of recovering generation sunk costs and the policy of reducing customers' rates when the utility's cost of service declines.

As the Commission has noted in other dockets, utility investment that exceeds market value (that is, "excess cost over market" or "ECOM") bears an increasing risk of under-recovery as the electric industry becomes more competitive.[21] Current ECOM of some generating facilities also represents an obstacle to the transition to increased competition and an impediment to some utilities' ability to compete. In EGS' case, the ECOM relates primarily to River Bend, but could be offset or affected by other, less expensive, generating assets. EGS' Plan proposed to address the ECOM issue by recovering the full net remaining cost of River Bend from its customers (less a minor amount attributable to the land on which River Bend sits), and thereby completely eliminate its anticipated ECOM exposure.

In the PFD, the ALJs concluded that EGS would have only $45.2 million in ECOM remaining on January 1, 2002, which is the assumed date by which the Legislature may mandate

[21] *Application of Central Power and Light Co. for Authority to Change Rates,* Docket No. 14965, Second Order on Rehearing at 2 (Oct. 16, 1997) (*CPL*). *See also Joint Application to Reduce Texas Utilities Electric Co. Base Rates and Approval of Certain Accounting Procedures,* Docket No. 18465, Order on Rehearing (June 25, 1998) (*TU Electric*); *Application of Houston Lighting and Power Co. for Change in Accounting Procedures and Approval of Certain Base Rate Credits,* Docket No. 18490, Order on Rehearing (June 25, 1998) (*HL&P*).

retail access.[22] The ALJs considered the $45.2 million figure to be negligible, and therefore recommended against any ECOM recovery mechanism.[23]

The Commission concludes that the record evidence in fact shows that EGS faces a significant ECOM exposure. To mitigate this exposure, the Commission authorizes EGS to recover approximately $120 million in an ECOM-related accounting order deferral (AOD), less approximately $41 million in related deferred taxes, plus approximately $4.7 million for deficient deferred taxes and revenue taxes, over a three-year period commencing June 1, 1996. Without this treatment, EGS would nevertheless be entitled to recover the AOD, but over the next 18 years. The AOD consists of costs that would otherwise have been expensed between River Bend's commercial in-service date and the effective date of the rates approved in the rate case in which River Bend was rate-based, Docket No. 7195, and related carrying costs.[24] Rates are now declining. By allowing the Company to surcharge the AOD expense over a three-year period, the Commission moves closer to intergenerational equity than would occur if future customers are required to pay the AOD over the remaining life of River Bend. Thus, the Commission's treatment both mitigates EGS' ECOM and better matches the recovery period for the AOD to the time period in which the AOD would normally have been expensed.

C. <u>Interruptible Service</u>

The Commission concludes that the current demand charge credits provided to the interruptible service (IS) customers will not be subject to partial imputation as recommended by the ALJs. The current IS demand and energy charges also will not be reduced in tandem with the base rate reductions applicable to firm customers. Instead, the demand and energy charges to IS customers, under the IS rider, will be frozen at current levels. This treatment results in the IS customers continuing to receive interruptible service at rates below firm service, but narrows the demand charge credit as base rates for firm customers are reduced. Also, by freezing the energy charges billed to IS customers under the IS rider, the Commission is ensuring that IS customers are allocated their fair share of transmission costs and, where applicable, distribution costs.

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22 According to the ALJs, EGS' ECOM is approximately $394 million in 1996 dollars.

23 PFD at 497-98.

24 Consolidated Docket Nos. 6477, 6525, 6660, 6748, and 6842, Order at Ordering Paragraph 7 (June 25, 1986); Consolidated Docket Nos. 7195 and 6755, 14 P.U.C. BULL. 1943, 2095-96 (May 16, 1988).

D. Overall Effect of this Order

The Commission affirms the majority of the PFD, but concludes that the record evidence requires modification to a number of findings and conclusions reached by the ALJs. In addition to the modification summarized above, the Commission modifies the ALJs' recommendations to conclude that (1) EGS' wheeling expenses and revenues should be subject to base rate treatment, rather than fuel reconciliation and fuel surcharges; (2) in recognition of the remedies established in EGS service quality case,[25] the Company's rate of return on equity (ROE) will be set at 11.1% for the period June 1, 1996 through May 12, 1998, and at 11.4% from May 13, 1998 through the remainder of the effective period of the rates in this docket;[26] and (3) the Company is also entitled to recover approximately $10 million more in fuel expense than recommended by the ALJs.

The following discussion addresses each of the Commission's modifications to the PFD and SPFD. The discussion does not track the sequence of the SOAH recommendations, but begins with the larger transition items arising in the competitive issues and revenue requirement phases. Discussion of the cost allocation/rate design and fuel issues follows in that sequence. This Order also includes a separate section addressing how refunds will be treated in this docket, including refunds resulting from a companion order on rehearing issued on September 2, 1998 in *Gulf States Utilities Company Remand of Actual Taxes Paid Issues,* Docket No. 18290.

Also attached to this Order are schedules detailing (1) the Company-wide Revenue Requirement and Invested Capital (Commission Schedules I through VI); (2) the Revenue Requirement and Revenue Deficiency (Commission Schedule KS-J1); (3) the Texas Retail Class Revenue Requirement Assignment, the Texas Retail Class Revenue Requirement Allocation, and the Texas Retail Class Rate Base Allocation (Commission Schedules KS-TX/1 through KS-TX/3, respectively); and (4) the Calculation of the Fixed Fuel Factor and the Allocation of Fuel Over/Under Recovery by Rate Class (Commission Schedules KP-Fuel/1 and KP-Fuel/2, respectively).

[25] *Entergy Gulf States, Inc. Service Quality Issues (Severed From Docket No. 16705),* Docket No. 18249, Order on Rehearing (April 22, 1998) (*EGS Service Quality*).

[26] The remedies established in *EGS Service Quality* will remain in place for some period beyond the rate period subject to this docket. Thus, the ROE reduction remedy will also apply in at least some portion of EGS' next effective rate period.

To the extent *not* addressed below, the Commission affirms the ALJs' discussions and proposed findings of fact (FoFs) and conclusions of law (CoLs) without substantive modification.

II. Discussion

A. Competitive Issues

1. ECOM

As noted by the Commission in *CPL*,[27] quantifying ECOM is a subjective process that "involves weighing conflicting theories and a broad range of estimates . . . proposed by expert witnesses." General Counsel submits that EGS will have $45.2 million in ECOM remaining on January 1, 2002. General Counsel's $45.2 million figure is derived from the ECOM model approved by the Commission in *Stranded Cost Report*, Project No. 15001. Similar to General Counsel, Cities submits that the Company's ECOM is a minimal amount. Texas Industrial Electric Companies (TIEC) and the Office of Public Utility Counsel (OPC) contend that the Company will actually over-recover ECOM through existing rates, and that its ECOM is and will be a negative number, potentially as much as negative $979 million, based on a net present value during the period 1998 - 2020.

EGS argues that its ECOM will be in excess of $200 million on January 1, 2002. By making just one correction to the General Counsel's application of the ECOM model relating to purchased power costs, EGS submits that its ECOM will be increased to, at a minimum, $136 million as of January 1, 2002.[28]

The ALJs conclude that General Counsel's estimate of $45.2 million in ECOM is the most reasonable and recommend that it be adopted by the Commission.[29]

The Commission accepts the General Counsel's $45.2 million ECOM estimate as a starting point. In applying the ECOM model, however, General Counsel did not properly account for the effect of purchased power costs on the ECOM estimate, thus significantly

[27] *CPL,* Second Order on Rehearing at 4.

[28] *See* discussion of ECOM estimates, PFD at 483-89.

[29] PFD at 490-98.

understating the estimate.[30] The Commission clarifies that it *is not* quantifying EGS' ECOM level, but concludes that EGS' ECOM is significantly higher than estimated by General Counsel.

Because EGS faces significant ECOM, and because the industry faces a period of increased competition and declining costs, it is appropriate to order ratemaking treatments that will allow EGS to accelerate and recover a portion of its ECOM. As in the *CPL, TU Electric,* and *HL&P* transition dockets, the Commission's policy is to authorize utilities to accelerate recovery of some portion (but not all) of their ECOM exposure in recognition of the current era of declining costs and increasing risk to long-term recovery of investment. In those dockets, the Commission implemented ECOM recovery mechanisms that directly accelerated a utility's recovery of its generation-related depreciation expense, or redirected transmission and distribution depreciation expense to the utilities' generation-related accumulated depreciation accounts.[31]

In this docket, a simpler and potentially less controversial ECOM recovery method is available. Schedule IV to the PFD indicates that EGS has an accounting order deferral (AOD) on its books valued at $178,462,000. This translates into a Texas retail AOD of $121,102,000, as shown on PFD-Corrected Schedule KS-J2. This $121 million AOD consists of costs that would otherwise have been expensed between River Bend's commercial in-service date and the effective date of the rates approved in the rate case in which River Bend was rate-based, and related carrying costs.[32] The purpose of the creation of the AOD was to mitigate the adverse effect of regulatory lag on GSU's financial integrity.[33] In addition, EGS has recorded $41,269,000 in accumulated deferred income tax (ADIT) that is related to the AOD.

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[30] *See* EGS Exh. 222, Schnitzer Rebuttal at 16-17 (PFD at 484).

[31] *CPL,* Second Order on Rehearing at 2-5; *TU Electric,* Order on Rehearing at 16-20; *HL&P,* Order on Rehearing at 16-19.

[32] Consolidated Docket Nos. 6477, 6525, 6660, 6748, and 6842, Order at Ordering Paragraph 7 (June 25, 1986); Consolidated Docket Nos. 7195 and 6755, 14 P.U.C. BULL. 1943, 2095-96 (May 16, 1988).

[33] Consolidated Docket Nos. 6477, et al., PFD at 25-26 (June 20, 1986); Consolidated Docket Nos. 7195 and 6755, 14 P.U.C. BULL. at 2121. The AOD will be fully amortized on December 10, 2010 at its current amortization rate. As an amortizing rate-based item, the Company also recovers a return on this deferred asset, and recovers income tax expenses related to the earned return.

While the Commission concludes that EGS faces significant ECOM as discussed above, an independent reason exists for allowing EGS to recover the AOD on an accelerated basis. Because the AOD is actually an expense that was incurred prior to River Bend entering rate base, the Commission could have added that expense as an operations and maintenance expense to base rates as soon as River Bend entered rate base. This treatment would have resulted in customers paying for the $120 million early in River Bend's life, rather than over an extended period. By not treating the AOD as a cost of service expense item, future customers would be paying for expenses that actually significantly benefited earlier customers. This creates an intergenerational inequity, but was necessary to avoid rate shock as discussed above.

Because rates and costs are now declining and the intergenerational inequity resulting from the AOD can therefore be ameliorated, the Commission concludes that it is appropriate to remove the AOD from rate base, and allow the Company to recover these deferred expenses over a three-year period as an offset to the base rate reductions ordered in this docket. The recovery of these deferred expenses must be reduced by the related ADIT to ensure that all effects of the AOD are removed from rate base. This accelerated recovery will also reduce the risk that the Company faces in recovering these deferred expenses in the current, more competitive, market. EGS is also entitled to recover additional revenues for the deficiency related to deferred taxes resulting from the change in tax rate, plus a gross-up amount for income tax, less the amount that should already be embedded in EGS' revenue requirement for the deficiency.[34] Further, EGS is entitled to an additional amount to cover the revenue taxes on the increased revenue EGS will receive due to the accelerated recovery of AOD.

For the historical period of June 1, 1996 through July 31, 1998, [35] the net revenues resulting from the acceleration of AOD (net AOD)[36] will be surcharged against the refunds made in accordance with the procedures set forth in the July 14, 1998 Interim Order Memorializing

[34] This additional revenue amounts to $31,029, plus $16,709, less $11,501, for an additional $36,237 per month, or $1,304,532 total over the 36-month recovery period.

[35] As discussed below, the dates setting the "historical period" and the "prospective period" are for illustrative purposes only.

[36] The net AOD consists of AOD, less related ADIT, plus the additional revenues discussed in the preceding paragraph.

Initial Refund Procedures issued in this docket (attached as Attachment A) as modified by this Order. For the prospective period of August 1, 1998 through May 31, 1999, the remaining unamortized net AOD expense will be surcharged against the base rates authorized in this docket. Even with this accelerated recovery of the net AOD, the Company's base rates will be reduced as a result of other rulings in this docket.

The Company is also authorized to collect interest on the unamortized portion of the net AOD, commencing on June 1, 1996, at an interest rate equivalent to the overall rate of return authorized in this docket (that is, 9.63% for the period June 1, 1996 through May 12, 1998, and 9.76% thereafter).[37] The Commission typically would set a lower rate of return on the accelerated portion of ECOM, as was done in the *CPL* transition docket. However, in this unique case, the return on ECOM is not lowered, based on a letter agreement between EGS and Cities which sets the interest applicable to base rate refunds at "Entergy's authorized overall rate of return established in the final order [in this docket]."[38] Because the Commission is accepting the provisions of that letter agreement as reflected in this Order, and because the AOD and associated ADIT are being removed from rate base, and because of the other ratemaking treatments adopted in this Order, the Commission concludes for policy reasons that the interest rate equivalent to the overall rate of return will also apply to the net AOD.

Based on the foregoing, the Commission finds in accordance with the Administrative Procedure Act (APA)[39] that the ALJs (1) did not properly apply applicable Commission policies or prior administrative decisions with regard to transition plans, and (2) with regard to the level of ECOM and ECOM recovery, recommended findings of fact that are not supported by a preponderance of evidence or in accordance with Commission policy.

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[37] Corresponding adjustments to the Company's ADIT account are necessary to match the new amortization schedule, but these book adjustments should not affect rates.

[38] *See* Letter from Mr. Frank Gallaher of EGS to Mr. Harry Wright dated May 7, 1996 (EGS Ex. 1 vol. 1, Application at 18 ¶ 26; General Counsel Ex. 61). In addition, as discussed in the Revenue Requirement/Rate of Return section below, this interest rate will change as of May 13, 1998.

[39] TEX. GOV'T CODE ANN. § 2003.049(g)(1) (Vernon 1998)

Accordingly, the following FoFs and CoLs are: modified-- FoFs 313, 338, 342, 352, and 359; added--FoFs 330A, 331A, and 337A through 337G; deleted--FoFs 324, 330, 339, 340, 343 through 349, 351, 353 through 354, 357, 358, 376, and 419 and CoLs 48 and 49.[40]

2. Earnings Cap

The ALJs recommend implementation of General Counsel's proposed earnings cap if the Commission authorizes accelerated recovery of ECOM.[41] The earnings cap mechanism suggested by the ALJs would apply any earnings above the authorized rate of return on equity to amortize regulatory assets and to accelerate recovery of River Bend. The Commission agrees in concept with the ALJs but concludes that an earnings cap would not serve a valid purpose in this particular docket because of the limited period over which the rates in this docket are expected to be in effect. In a case that would set rates well into the future, an earnings cap would complement the accelerated recovery of ECOM (in this case, the AOD). However, based on the provisions of the Stipulation and Agreement filed in EGS' (then Gulf States Utilities Company) merger case, Docket No. 11292, the effective period of the rate treatments in this docket will end in less than one year, and presumably no later than May 31, 1999. Because of the significant rate reductions and disallowances resulting from this Order, it is unlikely that EGS will be in a position to over-earn its authorized return during the effective period of these rates. An earnings cap implemented in this docket, therefore, would have minimal, if any, effect on reducing the Company's ECOM. The Commission encourages all parties in EGS' next rate case to develop some form of earnings cap to prevent overearnings, facilitate recovery of ECOM, and minimize the need for future rate proceedings.

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[40] On a related point, the Commission affirms the ALJs' conclusion that it is reasonable for EGS to continue to operate River Bend. The Commission, however, bolsters the ALJs' proposed FoF 377 on this issue by noting that River Bend does not emit pollutants such as NO_x, SO_x and CO_2.

[41] PFD at 510.

Accordingly, the factual circumstances involving the effective period of the rates in this docket require the deletion of FoFs 332, 333, 361, 362, 366, 368, and 369; the addition of FoF 362A; and the modification of FoFs 363 through 367.[42]

3. Performance-Based Ratemaking

The Commission affirms the ALJs on all but one aspect of their recommendation for approval of the River Bend performance-based ratemaking (PBR) mechanism. The PBR mechanism recommended by the ALJs applies a "deadband" around a targeted rolling average River Bend generating capacity factor of 81%. The recommended deadband is 78% to 84%. If River Bend generation capacity falls below 78%, a downward adjustment in EGS' ROE will be made; if the capacity exceeds 84%, the ROE will be adjusted upward in an amount equal to half the avoided fuel costs (that is, half the difference between actual nuclear fuel costs and the alternative energy rate). The Company's authorized ROE is not affected if the River Bend capacity factor remains within the deadband.

The Commission concludes that the 84% threshold level for earning an ROE reward is too low. The upper end of the deadband will instead be set at 86% as suggested by Cities and OPC. The record indicates that EGS should easily achieve an 84% reward threshold. By raising the reward threshold to 86%, the Company will have a greater incentive to achieve above-average performance, and thereby earn the reward recommended in the PFD.

The Commission also agrees with the ALJs regarding the use of long-term measures to reflect River Bend performance.[43] PBR measures shall be calculated annually, and EGS shall keep monthly records of River Bend's performance, outages, and monthly purchased power costs. Further, as recommended by the ALJs, the PBR plan prescribed in this Order shall apply to River Bend's operations effective July 1, 1996.

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[42] FoF 367 is also modified to acknowledge Commission policy that a utility's electric plant in service may not include capital additions in excess of 1.5% of the utility's net plant in service, unless the company demonstrates that a greater percentage of additions is reasonable.

[43] PFD at 554.

Finally, the Commission agrees with points raised by EGS and General Counsel on rehearing that the PBR fuel cost targets referenced in FoF 404 are intended to cover the amortization and lease interest portion only, and are intended to *exclude* Department of Energy fees.

Accordingly, the evidence regarding the appropriate capacity factor reward threshold for River Bend PBR requires the modification of FoFs 384, 385, 388, 389, 395, and 404; the addition of 413A; and the deletion of FoFs 386, 393, and 394.[44]

4. Retail Service Unbundling During the Transition Period

The ALJs recommend the unbundling of the Texas retail class cost of service into generation, transmission, distribution, and customer services. Distribution and customer services would be further unbundled into "basic, non-basic, and competitive services"; metering and billing would also be unbundled.[45] Functional and cost unbundling are high priority policy issues before the Commission at this time, and the ALJs' analysis is instructive. The Commission, however, has initiated two rulemakings to address these same issues on a state-wide basis--*Rulemaking on Unbundling of Electric Distribution Facilities and Functions,* Project No. 16536, and *Rulemaking on Unbundling Energy Services,* Project No. 19205. To ensure uniform and fair application of unbundling policies, the Commission concludes that EGS should be subject to the outcome of the pending unbundling rulemakings, rather than subject to the specific recommendations of the ALJs.

Accordingly, to apply developing Commission policy and rules with regard to functional unbundling, the Commission deletes FoFs 425, 426, 428, 429, 436, and 438; and modifies FoFs 437 and 461.

5. New Services and Pricing Initiatives

[44] The Commission also modifies FoFs 407 and 415 to clarify that the PBR plan approved in this docket is a fuel-only PBR plan. The Commission also modifies FoF 410 to note that, while it accepts a heat rate of 10,400 Btu/kWh as the average for gas-fired plants in Texas, this heat rate is high for new generation technology.

The PFD addresses a number of new service tariff proposals labeled as: General Customer Optional Pricing Program (GCOP), Large Customer Optional Pricing Program (LCOP), Competitive Pricing Service (CPS), Real-Time Pricing (RTP), Dynamic Time-of-Day (DTOD), Economic Development Rate (EDR) Rider, and the Employment and Economic Service Schedule (EEDS). The ALJs recommend rejection of GCOP, RTP, and DTOD. EGS withdrew EDR, to be replaced with a modified EEDS (to which the ALJs agree). The ALJs recommend adoption of the other new service tariffs with certain modifications.

Except for EEDS, the Commission concludes for policy reasons that all of these new service tariffs should be rejected at this time. This docket involves a huge array of novel and complex rate treatments designed primarily to deal with transition issues. The effects of these new offerings are not clear. Further, the Commission is concerned that these types of services, implemented at this time, may hinder the transition effort because they are competitive services offered by the utility prior to the advent of retail access. The Commission is willing to consider these types of services outside of this transition/rate case docket, and encourages the parties to develop such services on a revenue neutral basis. The Commission affirms the ALJs' proposed modifications to the EEDS tariff. Accordingly, for both policy and evidentiary reasons regarding the proposed new services, the Commission deletes FoFs 439 through 455.

6. Low Income and Environmental Initiatives, the "New and Unbundled Services" Plan, and Retail Access Pilot Program

The ALJs did not address the details of a non-unanimous stipulation on the Low Income/Low Use (LILU) Rider tariff reached between the Low Income Intervenors (LLI) and EGS, except to note that low-income programs will be needed once competition arrives. The purpose of this LILU rider is to make electricity more affordable for EGS' low-income customers. The Commission agrees with the non-unanimous stipulation and the general comments of the ALJs. The Commission therefore adopts the non-unanimous stipulation as in the public interest, and adds to this Order the five FoFs and three CoLs proposed by LLI in their brief on exceptions. The new FoFs and CoLs are FoF 480A through 480C and CoL 56A through 56C.

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[45] PFD at 566.

The Commission also affirms the ALJs' recommendation to approve, with modifications, EGS' proposed "New and Unbundled Services" (NUS) plan. The NUS provides a procedure for EGS to add, unbundle, or eliminate activities, services, products, and to implement pricing options. This plan may streamline the regulatory process, and may provide new services in anticipation of competition. The Commission, however, modifies FoF 461 by changing the provision requiring Commission approval of a NUS action from 45 days (as recommended by the ALJs) to 90 days. This change is predicated on the Commission's experience in the accelerated processing of telecommunications dockets involving applications for Service Provider Certificates of Operating Authority, which allow for a shortened review and approval process. The Commission considers 90 days as a minimum amount of time necessary to process and approve such applications.[46] The Commission also modifies CoL 54 to note that if the Company prices NUS service below fully-allocated embedded costs, the costs of serving the discount customer will be borne by EGS' shareholders.

General Counsel proposes implementation of a Retail Access Pilot Program. EGS argues that such a program is premature. The ALJs conclude that a retail pilot program is a reasonable step in the transition period, but recommend that the program be implemented in EGS' next rate case. The Commission agrees that a retail access pilot program is a valuable tool, but declines, at this time, to pursue such programs. In addition, with regard to pilot programs, the Commission would prefer that the Company support such a proposal before it is implemented. Accordingly, new FoF 465A is added to reflect the Commission's determination that it will not address retail pilot programs in this docket at this time.

The Commission also changes FoF 482 to reflect the Commission's decision that, if EGS does not file its report on the acquisition of Cajun's share of River Bend before it files its next rate case, the Company shall file its report in the next rate case.

7. Structure of the Bulk Power Market

[46] For the same reason, the Commission modifies FoF 289 to change the potential effective date of a new service offering under Schedule Premium Lighting Service (PLS) from 45 days to 90 days.

The PFD addresses a number of market structure issues involving a Regional Power Exchange (RPX), market power, divestiture, codes of conduct, predatory pricing, consumer protection, universal service, default providers, stranded benefits, supplier certification, and related economic and post-access issues. The ALJs' proposed FoFs 466 through 480 and CoL 56 address these issues. The Commission does not delete these FoFs and CoL 56 because they make generic statements regarding what may or should apply in a competitive retail market. These FoFs and CoLs, however, are not relied on to make any determinations in this docket. Rather, these types of issues are subject to the outcome of the pending rulemakings such as *Code of Conduct for Electric Utilities and Their Affiliates,* Project No. 17549, and *Review of Agency Rules in Accordance with HB1, Section 167, 75th Legislature (R.S.),* Project No. 17709. However, the Commission deletes FoF 469 in recognition of its policy that competitive restrictions *could* have effects prior to the advent of retail competition, particularly with regard to the wholesale market. The Commission also does not adopt proposed Ordering Paragraph 32, which would require EGS to file status reports on the RPX.

B. Revenue Requirement

1. Affiliate Expenses

EGS is wrong in its assertions that a "heightened scrutiny" of affiliate expenses developed *after* EGS filed its RFP in this docket.

> Affiliate transactions have been receiving greater attention in recent cases than they have in the past. [Citations omitted.] In [*Application of Tarrant Utility Co.*], a company's entire affiliate transaction expense was disallowed because of the failure of the applicant to carry the statutory burden of proof under PURA §41(c)(1). The Commission holding with respect to affiliate transactions was upheld by the District Court in the appeal of Docket 2914.

Application of Central Telephone Company of Texas for a Rate Increase Within Harris, Montgomery, Coryell and Burnet Counties, Docket No. 3510, 7 P.U.C. BULL. 185, 214 (April 20, 1981) (*Central).*

As is clear from *Central*, the Commission has placed a "heightened scrutiny" over affiliate expenses issues since at least 1981--fifteen years before EGS filed its RFP in this docket. Since *Central,* PURA has become even more explicit and, as explained below, the scrutiny has not lessened. In this docket, the Commission has gone out of its way to notify EGS that affiliate expenses are *and have always been* closely scrutinized in Commission rate cases. Because the Introduction to this Order addresses the affiliate expense issue in detail, the following discussion starts with the remand of Order No. 124 to the SOAH ALJs, and addresses additional tangential points raised by EGS on rehearing.

On remand of Order No. 124 (that is, EGS' third bite at the affiliate expense apple), the ALJ assigned to the revenue requirement phase first convened a hearing to determine whether EGS' existing reformatted evidence, together with *new* evidence, could support recovery of the affiliate expenses. The ALJ intended that if EGS' reformatted *and* new evidence could prevail against General Counsel's summary decision motion, the parties would then proceed to hearing on the actual merits of EGS' reformatted evidence only. Upon consideration of the reformatted and new evidence, the ALJ concluded in Order Nos. 143 and 144 that EGS, even with its new evidence, still had not met its burden with regard to the ESI expenses. With regard to EOI, however, and in consideration of the new evidence, the ALJ concluded that the EOI expenses could be allowed. EGS appealed Order Nos. 143 and 144 to the Commission, which the Commission denied. Thereafter, the ALJ proceeded to a hearing on the merits of the Company's EOI expenses, without the new evidence. The ALJ's determinations on all of these issues were carried with the case to be reflected in the PFD. In the PFD, the ALJ's primary recommendation is to disallow all ESI and EOI expenses. Alternatively, the ALJ recommended that the Commission accept only the *direct-billed* EOI expenses--$79.2 million (system-wide)--and disallow the $112 million (system-wide) related to ESI.

With one modification to correct a calculation error, the Commission concludes that the ALJ's alternative recommendation is the most appropriate in this docket. EGS argues in its brief on exceptions to the PFD that the EOI allowance should be $83,979,591 (system-wide), rather than the $79.2 million derived by the ALJs in their alternative recommendation. This $4.8 million difference corrects the error of twice subtracting ESI indirect charges for River Bend operations.[47] The Commission agrees with EGS on this point, and allows recovery of the $84 million (system-wide) in direct-billed EOI-related expenses.

[47] *See* EGS' Brief on Exceptions at 61.

The allowed EOI expenses are justified as reasonable in this docket because EOI direct-bills these expenses to EGS and the expenses themselves have been shown to be justified under the affiliate expense standard. The same conclusions cannot be made for the ESI expenses and EOI allocated expenses. These expenses have not been shown to be equal to or less than the prices charged by the supplying affiliate to its other affiliates, or to a non affiliated person for the same item or class of items. Indeed, these expenses are allocated (rather than direct-billed) to EGS through an extraordinarily complex and imprecise system of allocation formulas and billing methods.[48] As such, EGS' presentation does not comply with either the strict historical and clear standard of PURA § 36.058 or the precedent established in *Rio Grande*.[49] In *Rio Grande* in particular, the court held that to meet its burden of proof the utility must at least show, among other showings, that the price charged to the utility by its affiliate is no higher than the prices charged by the affiliate to its other affiliates, and each item or class of item was reasonable and necessary.[50] This standard also applies to all of the other cases cited by EGS in its motions for rehearing. In those cases, unlike this docket, the Commission was able to make the appropriate statutory findings to the extent it allowed utilities to recovery affiliate expenses.[51]

The Commission also explicitly denies two additional affiliate expense points raised by EGS on rehearing. First, it is disingenuous for EGS to argue that the Commission erred in refusing to allow EGS to enter new evidence into the record on remand of Order No. 124. EGS even accuses the Commission of a "misleading assertion" when the Commission based its

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[48] *See, e.g.,* PFD at 254-55, where the ALJ describes the difficulty in tracking one item and, nevertheless, not being able to determine the actual dollar amount because the items are presented on a total company basis.

[49] *Railroad Comm'n of Texas v. Rio Grande Valley Gas Co.,* 683 S.W.2d 783 (Tex. App. - Austin 1984, no writ) (*Rio Grande*).

[50] *Id.* at 786.

[51] For example, EGS cites *City of Abilene v. Public Utility Comm'n,* 854 S.W.2d 932, 946 (Tex. App. - Austin, 1993), *rev'd on other grounds,* 909 S.W.2d 493 (Tex. 1995) to argue that the Commission could approve affiliate expenses on a *total* affiliate basis. The error in EGS' rationale is that the Commission, in *City of Abilene, was* able to make a finding of fact that each of the allocation methods used by Southwestern Bell resulted in costs no higher than costs to other affiliates. The Commission also found that each of the methods produced "a reasonable result based on cost causation and benefit received." *Id.* at 946. The same conclusion does not apply to EGS--no such findings can be made in this docket because of the Company's failure to meet its burden of proof.

limited remand on EGS' statement that "all required evidence is in the record."[52] This statement is in no way misleading; it is an unqualified verbatim recitation of a statement made in a signed pleading filed by EGS in this docket. EGS, in its Brief in Opposition to Order No. 124 at pages 7-8 discusses the thousands of pages of data and witness testimony that it submitted in an attempt to prove up its affiliate expenses. Among other things, the Company states that

> This background data allowed the parties the opportunity to test EGS's contention *on an individual item--or work order--basis* (or on any combination of items) so that the parties could suggest and *the Commission could consider disallowances on an item-for-item basis*. This is the precise procedure the Commission has always followed for considering affiliate expenses.
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> On page 29, the Order [No. 124] cites the process required to pull together information about a given Service Request or work order. [Footnote omitted] Whether EGS might have used a different presentation format is not the issue; such complaints do not warrant summary disallowance of costs because:
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> 1) *All required evidence is in the record;*
>
> 2) *The parties have the data available in electronic format and can sort it in any manner they wish*, challenging the testimony of the witness offering same about any flaws or omissions;
>
> 3) During the hearing, *Dr. Buck offered to re-sort the existing evidentiary data in whatever manner the ALJ desired in order to facilitate her review*; . . . [53]

On rehearing, EGS argues that the foregoing verbatim quotation is qualified by statements made 20 pages later in a separate section of its Brief in Opposition to Order No. 124.[54] As highlighted in the foregoing quotation, EGS clearly did *not* limit its assertions only to total allocated expenses, but instead discussed the evidence as sufficient to allow the

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[52] EGS Second Motion for Rehearing at 63-64 (Sept. 24, 1998). At these pages of its motion for rehearing, EGS argues that pages 28-29 of its Brief in Opposition to Order No. 124 restrict the "all required evidence is in the record" statement to allocated affiliate expenses.

[53] Brief of Entergy Gulf States, Inc. in Opposition to Order No. 124 at 8-9 (Oct. 27, 1997) (emphasis added).

[54] Even on rehearing, the Company has yet to acknowledge its unequivocal statements on pages 8-9 of its Brief in Opposition.

Commission to consider disallowances on "an item-for-item basis." The foregoing quotation applies to evidence addressing *item-by-item* expenses.

Second, EGS argues that the Commission erred in barring the Company from making an offer of proof on certain evidence.[55] The ALJs, as upheld by the Commission, properly excluded EGS from making an offer of proof related to *other* parties' evidence. General Counsel, Cities, and OPC intentionally did not move their pre-filed direct testimony on affiliate expenses into the record. This direct testimony, therefore, was not "excluded" from the record by the ALJs and, as such, EGS has no right to compel the ALJs, other parties, or the Commission to admit that evidence into the record. Because the opposing parties did not put on a direct case, there is nothing for EGS to rebut. Accordingly, there is no ground for EGS to place its rebuttal testimony into evidence. Again, the problem here is not with the ALJs, other parties, or the Commission. The problem is with EGS' repeated failure to put on a coherent, *prima facie* case.

In conclusion, to date, the Commission has not dealt with an affiliate relationship issue even approaching the complexity of that presented in this docket. The Commission repeatedly prompted EGS to address its complex affiliate relationship in detail, and provided EGS with additional opportunities through supplemental direct testimony and the remand case to support its position. EGS' own witnesses recognized the high standard applicable to affiliate expense recovery, but failed to present a coherent, *prima facie* case in compliance with the statute. In the end, EGS failed to meet its statutory burden of proof due to its own inability to put on a persuasive affiliate expense case.

In consideration of the harsh result of disallowing all affiliate expenses, however, the Commission concludes that the EOI expenses in this docket are allowable on the basis of direct billing as discussed in the ALJs' alternative recommendation. But, as a matter of precedent, utilities are expected to meet the standard of proving the reasonableness of all affiliate expenses charged to the utility. This allowance of EOI direct-billed expenses is predicated on balancing all of the rate effects produced by this Order. In this Order, the Commission has implemented certain ratemaking treatments, such as accelerated recovery of the AOD and a move toward unity rates, based on the overall effect of the rate reductions ordered. If the level of these rate

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[55] EGS Second Motion for Rehearing at 67.

reductions were not present, the Commission would be compelled to modify its approach to ensure that the equities in this case continue to balance.

Accordingly, the following FoFs and CoLs are modified or added to reflect the Commission's acceptance of the ALJs' alternative recommendation regarding affiliate expenses: modified--FoFs 134, 149 through 151, 153, and 155 and CoLs 25 and 28; added--154A through 154D, and 228A, and CoLs 25A and 28A.

2. Effective Date of Rate Reductions

Based on recommendations by Cities and EGS, the Commission adds a new FoF 3A to reflect the effective date of rate reductions applicable in this docket. The new FoF is necessary to reflect the agreement of the parties and reads, in accordance with EGS' suggestions: "EGS agreed to make any base rate reductions ordered in this docket effective as of June 1, 1996 system-wide pursuant to an agreement with municipalities. EGS Ex. 1, vol. 1, Application at 18 ¶ 26; GC Ex. 61."

3. Plant Held for Future Use

The ALJs recommend against EGS' request to include $56.6 million in rate base attributable to mothballed production facilities because EGS failed to show that it has a definite specific and reasonable plan to return these facilities to used and useful service within ten years. The ten-year standard applies under the Commission's current "Plant Held for Future Use" (PHFU) standard.[56] The Commission agrees with the ALJs' recommendation.[57] The Commission, however, adds a new FoF 113A to clarify that, due to changes in the law and industry, it will no longer adhere to the PHFU standard, or any standard that anticipates recovery of new or mothballed generation plant investment through rate base. This new policy is necessitated by advancing competition in the wholesale market at both the federal and state levels. In this new era of increasing competition among generation capacity suppliers, utilities

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[56] The precedents setting forth this standard are listed in PFD footnote 494.

[57] The Commission modifies FoF 111 to clarify the ALJs' exclusion of certain transmission-related facilities: Right-of-Way 803 and five acres adjacent to the Orange substation.

should no longer either construct new generation facilities, or attempt to place mothballed generation facilities into rate base. Instead, utilities should acquire new generation capacity from non-utility suppliers (which may include affiliates of the utility) through the Integrated Resource Planning (IRP) solicitation process set forth in PURA Chapter 34 and the P.U.C. SUBST. R. 25.161 through 25.171. To clarify further, EGS' upcoming proposed Preliminary IRP shall not reflect the capacity attributable to the mothballed facilities as capacity available for its future needs. This clarification does not, however, preclude capital additions by the utility to maintain existing, on-line generation plants, or to make existing facilities more efficient.[58]

4. Fuel Oil Inventories

EGS requested a fuel oil inventory working capital allowance of $6,744,663. The ALJs recommend an allowance of $2,085,630, the difference ($4,659,033) being attributable to No. 6 fuel oil. The ALJs recommend disallowance of the No. 6 fuel oil expense because they conclude that No. 6 fuel oil was not necessary to cover any back-up fuel oil needs at the Sabine and Willow Glen natural gas-fired generating stations.[59] Both EGS and General Counsel excepted to the ALJs' proposed disallowance of the No. 6 fuel oil-related inventory expense. They argue that the ALJs in effect are recommending an improper double disallowance because, in the SPFD, the ALJs recommend disallowance of certain natural gas expenses related to fuel burns in February of 1996. As stated by General Counsel, "[t]he Commission therefore should not disallow imprudent fuel costs related to EGS's failure to burn fuel oil, on the one hand, and refuse to include the fuel oil in inventory, on the other."[60]

The Commission agrees with General Counsel and EGS; if the February 1996 natural gas expenses are to be disallowed as imprudent (which they are, as discussed below), the Company should be permitted to recover the costs of the No. 6 fuel oil that it should have burned in lieu of

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[58] The Commission also notes and corrects an error related to PHFU that is reflected in PFD Schedule IV. As indicated by EGS and General Counsel in their second motions for rehearing, the "Accumulated Depreciation" adjustment in column 4 of Schedule IV should be $43,185,000, rather than $34,466,000. Because this correction affects invested capital and return calculations, the other revenue, allocation, and refund schedules must also be modified to reflect this correction.

[59] PFD at 175-77.

[60] *See* General Counsel's Brief on Exceptions at 18.

the disallowed high cost natural gas. Accordingly, to reflect the preponderance of evidence in the record, FoF 117 is modified and FoF 117A is added to find that the fuel oil working capital in rate base is $5,110,085, rather than $2,085,630.

5. Return on Equity

The Commission affirms the ALJs' recommendation to set the Company's ROE at 11.7% in this docket with the following modifications. First, the Commission acknowledges that an appropriate range for EGS' ROE is 9.65% to 13.94%. This range is based on both the constant growth and the multi-stage non-constant growth discounted cash flow (DCF) analyses. As the ALJs recognized, using both of these models more closely resembles the balance employed by the Commission in Docket No. 14965. Accordingly, FoFs 128 and 129 are modified, New FoF 128A is added, and FoFs 130-132 are deleted. Additionally, the Commission modifies FoF 134 to reflect that, although adjustments to EGS' ROE were not modified in this case for poor demand-side management and affiliate transactions, the Commission retains full discretion to make such adjustments in a future case.

Second, a new FoF 128B is added to reduce the 11.7% ROE by 60 basis points to 11.1% for the period June 1, 1996 through May 12, 1998, and by 30 basis points to 11.4% from May 13, 1998 through the remainder of the period in which the rates subject to this docket are in effect. This bifurcated ROE reduction is required by the Commission's determinations in the related *EGS Service Quality* proceeding (Docket No. 18249), which concluded that the ROE ultimately authorized in this docket (Docket No. 16705) would be reduced permanently by 60 basis points from the date refunds become effective in this docket "through the effective date of [the final order in Docket No. 18249]."[61] After the effective date of the final order in Docket No. 18249 (that is, May 12, 1998), the authorized ROE in Docket No. 16705 is increased by 30 basis points to 11.4%, but the Company must escrow that 30 basis points of ROE. As provided in *EGS Service Quality,* the Company will be permitted to retain up to the full amount of the escrowed 30 basis points if it meets certain service quality benchmarks established in that proceeding.[62] If it does not meet those benchmarks, some portion or all of the escrowed amount will be refunded

[61] *EGS Service Quality* Order on Rehearing at 51 (Ordering Paragraph 3).

[62] *Id.* at Ordering Paragraph 5.

to customers, thus effectively resulting in a minimum ROE of 11.1%. These ROE reductions are not predicated on a finding that the ALJs erred in recommending the 11.7% ROE. Rather, they are based on the Commission's rulings in *EGS Service Quality*. Accordingly, new FoF 128B is not a modification to the ALJs' ROE recommendation subject to APA § 2003.049(g), but rather is made to conform the ROE in this docket to the rulings in Docket No. 18249.

Third, the reduction to the Company's authorized ROE also results in a reduction to the ALJs' recommended return on invested capital.[63] This authorized overall return dollar amount is therefore reduced as reflected on the attached Commission Schedules I and IV. In addition, FoFs 134 and 135 are modified respectively to clarify that only the direct-billed EOI expenses are approved in this docket, and to reflect the adjustment to the overall cost of capital as a result of the Commission's decisions in *EGS Service Quality*.

6. Amortization Expense

The amortization expense reflected on Schedule I must be decreased to reflect the removal of $9 million in annual amortization expenses related to the AOD discussed in the Section II.A.1 (Competitive Issues, ECOM) of this Order. The accelerated amortization of the $121 million AOD is reflected in the attached schedules. Other corresponding adjustments to the federal income tax allowance must also be made. These adjustments are reflected in the attached schedules. The FoF dealing with amortization expense--FoF 191--is modified to reflect the Commission's conclusions that the rate period for this docket, and for the amortization expense period, extends from June 1, 1996 through an assumed May 31, 1999 ending date.

7. Wheeling Expenses and Revenues

EGS requested a good cause exception to the Commission's fuel rule, PUC SUBST. R. 23.23(b)(2)(B), to treat wheeling expenses booked to Account 565 and wheeling revenues as base rate items. The wheeling expenses are $12,098,918 paid by EGS to other Entergy operating companies under Service Schedule MSS-2; the wheeling revenues relate to wheeling transactions

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[63] This figure is the corrected amount reflected in Schedules I and IV of the ALJs' June 12, 1998 clarification. The original PFD recommends a slightly higher figure. PFD at 317.

for Access and Company Service in the amount of $36,066,060, resulting in net revenues $23,967,142. The $12.1 million in Service Schedule MSS-2 expenses are "transmission equalization payments" (TEPs) which, in effect, pool the ownership costs of certain, mostly high-voltage transmission facilities owned by the Entergy utilities, and reallocates the costs back to the operating companies on an equalized basis. EGS, as a relatively transmission-deficient utility, pays TEPs to other Entergy operating companies to compensate them for their higher level of transmission capacity investment. The Access and Company Service revenues are revenues received by Entergy or EGS for wholesale transmission service.

The Account 565 expenses and wheeling revenues historically have been treated as fuel-related items subject to fuel reconciliation and recovery through fuel factors, rather than through base rates. In the PFD and SPFD, the ALJs recommend base rate treatment of these expenses and revenues *for purposes of reconciling the fuel expense* subject to this docket, but recommend denial of EGS' request for base rate treatment *for purposes of establishing the final fuel factor*. In doing so, the ALJs recommend as follows:

1. Reclassify $12,098,918 of FERC Account 565 expenses from O&M Not Adjusted to fuel expense (that is, disallow the $12.1 million from base rates, but allow recovery through the fuel factor); and

2. Decrease the Company's requested fuel expense by $36,066,060 to "Access and Company Service" revenues.

After the ALJs issued the PFD and SPFD, the Commission clarified its policy on the recovery of TEPs to conclude that TEPs paid by non-ERCOT utilities are not fuel-related expenses. As such, TEPs should be recovered through base rates rather than through the fuel factor.[64] This base rate treatment recognizes that the TEPs that comprise EGS' Account 565 expenses are not actually related to the cost of purchasing or transporting fuel or purchased

[64] *See Application of Southwestern Electric Power Company for Reconciliation of Fuel Costs, Surcharge of Fuel Cost Under-Recoveries, and Related Relief*, Docket No. 17460, Order at 1, 10-11 (May 20, 1998) (*SWEPCO*). The distinction between ERCOT and non-ERCOT utilities arises because ERCOT utilities are subject to the Commission's uniform transmission pricing rules, while non-ERCOT utilities are not, and because the Commission is in the process of reviewing its ERCOT transmission pricing rules to address the components of the transmission rates.

power for the EGS system; they are demand-related, not energy-related. Similarly, the $36.1 million in wheeling revenues should be treated as base rate revenues, rather than fuel-related revenues, because these revenues are not energy-related. As a further clarification, the Commission notes that base rate treatment of these Account 565 expenses and wheeling revenues is restricted, at this time, to non-ERCOT utilities such as EGS.[65]

Accordingly, based on the policies clarified after issuance of the PFD and SPFD, PFD FoF 220 is deleted and PFD FoFs 82, 207, and 218, and CoLs 7, 8, and 11E are modified to find that base rate treatment for wheeling expenses and revenues is appropriate under the principles announced in *SWEPCO*. The Commission also modifies FoF 219 to clarify that the service transmission tariff should be treated separately from the access transmission tariff. Fuel factor and fuel reconciliation issues are also addressed below in the Fuel section of this Discussion.[66]

8. Capital Additions

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[65] The Commission also concludes that wheeling classes should be included as separate classes in the Company's cost of service studies. This separate treatment recognizes the policy of treating wheeling expenses and revenues as base rate items, rather than as eligible fuel items.

[66] The Commission here notes a number of apparently non-controversial corrections that should be made to specific revenue-related items.

First, the Commission corrects a minor typographical error to the recommended capital ratio as noted by EGS and General Counsel in their exceptions. The percent of common equity as compared to the overall capital should be 43.26%, rather than 43.25%. FoF 125 is corrected accordingly.

Second, EGS itself recommended removal of $441,000 associated with advertising to promote electricity usage, and $445,000 associated with a River Bend Outage accrual. The PFD, however, does not reflect these Company-requested removals. Accordingly, FoFs 139A through 139C are added to reflect removal of these items from payroll expense. *See* EGS' Replies to Exceptions at 25-26.

Third, FoF 143 is modified to correct a double-counting adjustment applicable to pension benefits. The Company had already made this adjustment; accordingly, FoF 143 is modified by $414,824 from ($3,575,835) to ($3,161,001). *See* EGS' Brief on Exceptions at 42.

Fourth, the ALJs recommended adoption of General Counsel's mass property depreciation rates but, in its replies to exceptions, General Counsel agrees with Cities that its net salvage for Account 367 was in error based on incorrect information originally provided by EGS. With the corrected information, General Counsel recommends that the appropriate net salvage for Account 367 should be 0%, rather than -5%. The PFD does not include an FoF addressing Account 367 and, therefore, no modification to the PFD is necessary. However, the Commission concludes that General Counsel's corrected net salvage rate applies for Account 367.

Fifth, CoL 20 is corrected to reflect the ALJs' decision made in FoF 167 and the text of the PFD, as affirmed by the Commission, to allow recovery of Edison Electric Institute dues.

In the PFD, the ALJs describe confusion regarding the actual amount of capital additions requested by EGS for River Bend.[67] Based on EGS' first motion for rehearing, and Cities' response to that motion, the Commission modifies FoF 100 to clarify that the *net* of capital additions and *capital retirements* since EGS' *last rate case* were reasonable and necessary.

9. Accumulated Deferred Federal Income Taxes

A portion of EGS' accumulated deferred income taxes is related to the AOD as discussed in Section II.A.1 above. This AOD-related ADIT in the amount of $41,269,000 must also be removed to effectuate a total removal of the AOD from rate base. New FoF 107A is added to reflect the removal of AOD-related ADIT.

In addition, FoF 106 is modified to reflect the proper amount of net operating losses (NOLs) to be removed from rate base. This adjustment removes the double-counting of the $1,926,024 return to accrual adjustment recommended by the ALJs.

10. Federal Income Tax

FoF 199 is modified to reflect that EGS is to amortize the excess deferred federal income tax related to the $64 million write-off related to River Bend.

C. Cost Allocation and Rate Design

1. Interruptible Service

EGS provides interruptible service under its IS rate schedule, which is available to customers taking firm service under the High Load Factor Service (HLFS) and Large Power Service (LPS) rate schedules. The IS "rate" is actually a credit to the demand charges paid under the HLFS or LPS firm rate schedules, rather than a calculated price for stand-alone interruptible service. Prior to the effective date of rates in this docket, IS customers willing to be interrupted without prior notice received a 100% demand charge credit, meaning they are fully reimbursed by EGS for their demand charges otherwise owed under the applicable firm rate schedules. Five-

[67] *See* PFD at 141-44.

minute prior notice interruptible customers receive a demand charge credit of 63% (HLFS) and 70% (LPS) of their otherwise applicable demand charges; thirty-minute prior notice customers receive a demand credit between 33% to 40%.[68] During the test year subject to this docket, IS customers as a whole received demand credits from EGS totaling $10.8 million.

The ALJs recommend that EGS' shareholders should absorb approximately $4.5 million of the $10.8 million in demand charge credits. The ALJs do not conclude that IS service is a discount rate subject to PURA § 36.007. They instead conclude that IS service is not properly priced noting that, on EGS' system, interruptible service may not be a lesser quality of service (as compared to firm service), and "interruptible customers are being subsidized and that the amount of the demand charge credits are too great."[69] The effect of the ALJs' recommendation would recognize that, based on firm rates during the test year, the total annual IS credits should be approximately $6.3 million ($10.8 million minus $4.5 million).

The Commission affirms and clarifies that IS service is an interruptible service. The demand charge credits do not constitute discount rates and IS service is a valuable demand side resource. Consistent with the ALJs' conclusions, the Commission agrees that the current IS service is not properly priced, and that the total annual IS credits should have been in the range of $6.3 million, rather than the $10.8 million in credits applied to firm rates during the test year. Because the IS service is an interruptible service rather than a discounted firm service, the Commission does not order imputation of any portion of the demand credits to shareholders as suggested by the ALJs. Instead, the Commission takes an interim action to reduce the magnitude of the demand credits to IS customers. The Commission orders that the effective IS demand and energy charges be frozen at their current levels. By freezing the current effective IS rates, the IS customers will continue to receive a credit that reduces their interruptible demand charges below the firm demand charges. However, the resulting credit will be less than would apply if the IS demand and energy charges moved down in proportion to the firm demand and energy base rate reductions otherwise ordered in this docket.

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[68] For example, assume that an HLFS customer is subject to the five-minute prior notice IS provision. If that customer's firm HLFS demand charge is $10 per kW, but the five-minute rider provides a 60% demand charge credit, that customer's IS demand charge is $4.00 per kW (.60 multiplied by $10.00 per kW).

[69] PFD at 426-27.

In addition, there is no evidence in the record that the IS demand charges were designed to recover transmission and distribution costs. The Commission's decision to freeze the IS energy charges in addition to freezing the demand charges is designed to ensure that the IS customers pay their fair share of transmission-related costs and, where applicable, distribution-related costs. Freezing the IS demand and energy charges is an interim step toward eliminating the current interruptible rates, and replacing them with market-based rates as ordered hereafter. This treatment recognizes that the IS rates are not discount rates, thereby precluding the charge of any excess credits to the EGS shareholders, which action could provide EGS an incentive to discontinue offering interruptible service. Freezing the rates allows rate stability and certainty to the IS customers, while significantly reducing the cost-shifting of excess credits to firm customers. This interim action represents a fair balance to the EGS shareholders, firm customers, and interruptible customers until the current IS rates are replaced with market-based rates.

The Commission's treatment of interruptible service as described above requires additional clarifications. First, the firm customers' overall base rates will be reduced significantly in this docket, but they will be subject to surcharges related to fuel, the AOD, and the tax remand from Docket No. 18290. Because the Commission is freezing the IS customers' demand and energy charges at current levels, and not reducing those charges proportionately to the firm base rate reductions, the Commission concludes that the IS customers should only be subject to the fuel surcharge, and that surcharge should be spread out over twelve months commencing with the effective date of this Order. The IS rates will not be subject to the AOD and tax remand surcharges ordered in this docket.

Second, the Commission concludes that it is appropriate to impose a remediation treatment similar to that adopted in *CPL*. As in *CPL*, EGS' current IS service will be eliminated on the third anniversary of the effective date of this Order. Further, as also applied in *CPL*, interruptible service will be closed to new customers during this three-year transition period until a redesigned interruptible service is approved. In the proceeding in which the redesigned interruptible service is approved, the parties shall explore the issues of the proper size of the interruptible resource in available megawatts. In the instant docket, the parties have already explored the proper pricing of interruptible service. The ALJs implicitly recommend that this service has a value of \$6.3 million (\$10.8 million minus \$4.5 million). The Commission concludes that this value is a reasonable approximation, but the parties should update this value as appropriate. In summary, as in the Central Power and Light IRP proceeding, EGS' interruptible service will not actually be discontinued, but will be reformed as a supply resource sized and priced in accordance with the IRP policies.[70]

Accordingly, to properly apply existing Commission policy and prior decisions on interruptible service as reflected in the *CPL* rate case and IRP dockets, the Commission modifies FoFs 253, 260, 262, and 267, deletes FoF 263, and adds FoFs 260A and 267A and B.

2. Discount Rates

As stated, the ALJs conclude that IS rates are not discount rates; they also conclude that Economic As-Available Service (EAPS) rates are not discount rates. However, they recommend findings stating that the following rate schedules prescribe discount rates: Industrial Service to Qualifying Thermal Energy Users (SUS), Rider for Institutions of Higher Education (IHE), Supplemental Short-Term Service (SSTS), and Employment and Economic Development Service (EEDS).[71]

The Commission affirms the ALJs on each of these recommendations and here clarifies its interpretation of the discount rate standards of PURA § 36.007. These clarifications are necessary to explicitly reject certain arguments made by EGS and TIEC regarding the applicability of the discount standard.[72]

First, EGS and TIEC argue that § 36.007 applies only to rates implemented on or after the September 1, 1995 effective date of the 1995 changes to PURA, and not to previously approved

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[70] *See Joint Application of Central Power and Light Company, West Texas Utilities Company, and Southwestern Electric Power Company for Approval of Preliminary Integrated Resources Plan and Related Good Cause Exceptions,* Docket No. 16995, Interim Order on Interruptible Phase (April 13, 1998).

[71] PFD at 399. EGS apparently agrees to revenue imputation for the SUS and IHE rates. *Id.* at 393.

[72] The Commission, however, explicitly modifies CoL 54 to clarify that costs below the "fully allocated" embedded cost of a rate are costs that will be borne by the Company's shareholders.

rates. The Commission concludes that § 36.007 applies to all discounted rates, new and old, and not merely to new proposed rates and rate schedules.

Second, EGS argues that the term "allocable costs" as used in § 36.007 means "incremental costs," and this interpretation is consistent with sound policy to encourage a utility to attract loads which contribute to embedded costs. The Commission concludes that the term "allocable costs" as used in the discount standard means "average embedded cost" and it is sound public policy to require the shareholders to bear the cost of any discount necessary to attract customer loads that have competitive alternatives.

Third, EGS and TIEC argue that SSTS and EAPS (and IS) offer a lower quality of service, while a discount service is one that offers the same quality of service at a lower rate. The Commission concludes this argument is flawed because: lower quality in name may not equate to lower quality in fact, and pricing should reflect the quality of service received.

Fourth, in the context of the EEDS and SSTS rates, EGS proposes three tests to determine whether a rate is a discount rate.[73] These tests, with the Commission's conclusions, are summarized as follows:

a) Was the rate in place prior to the effective date of PURA95? The Commission concludes that this test is irrelevant because § 36.007 is a statutory standard that must be applied in each proceeding.

b) Does the rate offer the same type, kind, and quality of service as an existing rate? The Commission concludes that this test is subject to controversy. An applicant could argue that every proposed rate, however discounted, offers a different "type, kind, or quality" of service. Meaningful service choices ought to be provided to all classes for equity reasons, and consequently every tariff could be labeled "different" and not subject to § 36.007.

c) Was the rate designed to serve marginal load; that is, load that would not be connected but for the rate? The Commission concludes that this test is also subject to

[73] *See* EGS' Brief on Exceptions at 84-85.

controversy. Marginal loads are not easily identified; each customer whether "marginal" or "captive" makes incremental purchases each month under typical tariffs; every customer prefers marginal cost pricing when marginal costs are below average embedded costs; some customers may claim they would not connect unless they receive a lower, marginal rate when, in actuality, they would be willing to connect at a higher rate.

The foregoing clarifications result in a modification to FoF 252 to clarify that SUS and IHE, in addition to EEDS and SSTS, are considered discount rates.[74]

3. Revenue Distribution Among Customer Classes

a. <u>Relative Rate of Return</u>

The ALJs recommend approval of General Counsel's recommended distribution of the revenue decrease that will result in this docket based on the relative rankings of percentage decreases reflected in column 4 of Schedule KS-TX/1 (corrected). Revenue distribution is the process by which class base rate revenues are determined for each customer class. Adjustments to the revenue distribution indicated by a cost of service study are necessary to take into account the relative rate of return of the classes. Relative rate of return is a measure of the degree to which a class is paying its cost of service. A relative rate of return of greater than 1.0 indicates that a class is paying more than its cost of service. A relative rate of return less than 1.0 indicates that a class is paying less than its cost of service. Because of the significant base rate reduction that will result from this docket, an opportunity exists to move all classes closer to unity without increasing the revenue responsibility of any class.

The Commission agrees with the ALJs' general recommendation to move toward relative rate of return unity, but takes the next step here by establishing rates that actually reach unity. The percentage revenue decreases reflected in General Counsel's proposal and in the corrected Schedule KS-TX/1 (now reflected on attached Commission Schedule KS-TX/1), however, are

[74] With regard to SSTS rates, the Commission notes that the SSTS-related revenue imputed to EGS' shareholders should be $7,282,000, rather than the $14.1 million reflected in earlier Commission orders issued in this docket.

changed to account for the revisions to EGS' revenue requirement and base rates as reflected in this Order. The revenue decreases are changed as necessary (1) to move all classes to unity, and (2) to provide the highest percentage revenue decreases to the classes that have experienced the highest relative rate of return under the cost of service study. FoF 245 is modified to reflect the Commission's conclusion that all classes will be moved to unity, rather than simply "closer to" unity.

b. The LPS and HLFS Class Allocation and Rate Design

The ALJs recommend combining the LPS and HLFS classes for cost of service study/cost allocation purposes.[75] They also recommend approval of EGS' proposed rate design of the LPS and HLFS rates.[76] On exceptions, however, EGS asserts that there is no longer a Company-proposed rate design because the ALJs (and now the Commission) have rejected EGS' proposed unbundling charge, Universal Service Charge, and the reclassification of nuclear fuel from fuel to base rates.[77] No party addressed this issue in replies to exceptions.

The Commission cannot agree to the ALJs' proposed combination of LPS and HLFS for cost study/allocation purposes without changing the existing separate rate designs for these two classes. To do the former would result in the LPS and HLFS classes *not* being at a unity relative rate of return. Accordingly, to achieve the unity goal, these two classes shall not be combined for cost of service study purposes. FoF 244 is modified to reflect this policy consideration.

This unity problem, however, can be resolved in the compliance filing to be made by EGS in this docket. Therefore, while the Commission maintains LPS and HLFS as separate classes for the cost of service study, EGS shall, in its compliance filing, revise the rate design for the LPS and HLFS classes to ensure that the cross-over point at which the rates of these two classes equal is approximately the 80% load factor point.

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[75] PFD at 383-84.

[76] PFD at 444.

[77] EGS Brief on Exceptions at 91.

4. Changes or Clarifications to Other Cost Allocation and Rate Design Recommendations

The Commission's remaining changes to the cost allocation/rate design FoFs and CoLs are based on both policy and evidentiary conclusions that differ from those of the ALJs. These technical changes are relatively non-controversial and are addressed in summary fashion in this section. Clarifications and future filing requirements are also addressed.

As a preliminary matter, the Commission agrees with EGS' statements on rehearing that it is good public policy to encourage economic development in Texas.[78] The Commission does *not* disfavor or discourage economic development programs. In this Order, however, the Commission disallows EGS' claimed expenses relating to economic development programs because, as reflected in FoF 206, EGS has failed to show how its economic development research programs (which are part of its DSM program expenses) benefit ratepayers.

The remaining clarifications necessary to reflect the Commission's policy and evidentiary conclusions regarding cost allocation and rate design issues in this docket are as follows:

1. Weighted billing cycle data should compare one month of weather data to one month of sales, rather than two months of weather to one month of sales as recommended by the ALJs. FoF 210 is changed accordingly.

2. The Commission would prefer development of a separate weather adjustment for each of the three commercial classes, but agrees with the ALJs that EGS' proposed adjustments are flawed because the Company did not use a uniform method of weather adjustments.[79] Because the quality of EGS' data is questionable, separate weather adjustments for each commercial class are not possible in this docket.

3. With regard to the jurisdictional cost allocation of special rate revenues, the ALJs should have required the direct assignment of special rate revenue to the jurisdiction

[78] EGS Second Motion for Rehearing at 19.

[79] PFD at 330-31.

of origin. Direct assignment, rather than allocation as recommended by the ALJs, will preclude the $396,000 subsidy from Texas to Louisiana. A new FoF 217A is added to reflect this change.

4. Allowed EOI-related affiliate expenses shall be allocated consistent with the rate design established in this docket. A new FoF 228A is added to reflect this directive.

5. The ALJs recommend that Texas revenue-related taxes be allocated on the basis of retail revenue only. The Commission disagrees. Because revenue-related taxes are derived based on total company revenue, not simply retail revenue, allocation of total company revenue-related taxes to both Texas retail and wholesale customers is more appropriate. Accordingly, FoF 235 is changed to reflect total company revenue allocation.

6. FoF 276 is deleted because this finding improperly assumed rate levels applicable to the high load factor customers based on no revenue reductions. Because revenues are reduced in this docket, the FoF is erroneous, does not apply, and is deleted.

7. General Counsel proposed new additional time-of-day (TOD) rates in an effort to increase customer choice and options. The ALJs were not convinced that the new rates would have any greater effect on EGS' customers' willingness to shift usage to off-peak times and might actually create greater confusion and inaction. The ALJs therefore recommend against adoption of the new rates, but suggest that greater promotion should be tried first before customers are presented with such alternatives.[80] The Commission agrees with the ALJs' recommendation, but requires that EGS address these types of new TOD rates for smaller customer classes in a new tariff offering. For now, EGS shall continue to offer its existing TOD rates. In its upcoming IRP docket, or in its November 1998 rate case, whichever is initiated first, the Company shall also indicate how it intends to promote new TOD rates to its customers. Accordingly, FoF 279 and 281 are modified to note that TOD rates were

[80] PFD at 454.

not sufficiently promoted in the past, and the Commission shall address promotion of TOD rates in a new tariff offering.

8. The Commission affirms the ALJs' recommendations regarding approval of: Premium Lighting Service,[81] Rider AFC (Additional Facilities Charge), and EGS' proposal to charge market prices for meter sockets.[82] The Commission clarifies, however, that these services will be subject to the final rules to be adopted in the functional and energy services unbundling rulemakings pending in Project Nos. 16536 and 19205.

9. The PFD omitted certain miscellaneous rate-related proposals by the Company that are not opposed by other parties. The Company proposed two new lighting rates within the Area Lighting Service Schedule (ALS). The Company also proposed to revise the "sunset" provisions to the SSTS and EAPS tariffs. The Company proposed to make certain application and other wording changes to the Experimental Rider to Schedule RS for Good Cents Homes, Residential Street Lighting Service, Unmetered Service, Experimental Rider for Water Heating Service and Schedule SMC. The Company also proposed minor and unopposed clarification wording changes to some of the tariffs. The Commission grants these proposals, and therefore adds FoF 300A.

10. The Commission concludes that it is reasonable to spread the cost of Rider RS, designed for low-income senior citizens, over all classes of customers. Therefore, FoF 277 is modified.

11. The Commission clarifies that not all proposed changes to the MES tariff were approved. Therefore, FoF 286 is deleted.

12. The Commission approves a change in the on-peak hours from 11:00 a.m.-9:00 p.m. to 1:00 p.m.-8 p.m. for the Pipeline Pumping Service (PPS) to match the hours to EGS' Louisiana tariff. Accordingly, FoF 284 is modified to reflect this change.

[81] Except that the period for approval of new offerings under Schedule PLS (FoF 289) is modified as discussed in Section II.A.6., above.

13. In its second motion for rehearing, EGS requests that the Commission use the Company's jurisdictional and class cost allocations for permanent differences, depreciation adjustment, and temporary adjustments in calculating the Texas retail jurisdictional and class amounts for these items. General Counsel concurs, and the Commission grants EGS' request. There are no changes necessary to FoFs or CoLs to reflect this change.

D. Fuel

The SPFD and Sections III and IV of the PFD address fuel issues generally, the fuel factor, and fuel reconciliation issues. The SPFD FoFs are incorporated into the attached FoFs as FoFs 96A through 96Q, 82A through 82C, and 32A through 32 F. The SPFD CoLs are likewise incorporated into the attached CoLs.

1. Contemporaneous Documentation

In the PFD, the ALJs express concern over the lack of contemporaneous documentation made or retained by EGS to justify the level of its claimed fuel expenses. They conclude that in many instances involving fuel-related purchases or sales:

> EGS simply failed to conduct any analyses, or if it did conduct analyses, it did not reduce them to paper (or silicon), or if it did memorialize the analyses in documents, it did not retain and maintain them. EGS suggested that credible testimony by witnesses with personal knowledge can satisfy the burden of proof despite a complete lack of contemporaneous documentation. [footnote omitted] The ALJs believe that, in the abstract, this is likely a correct view of the burden of proof, though EGS appears to underestimate the steep uphill nature of that evidentiary path.[83]

The Commission agrees with the ALJs' discussion regarding contemporaneous documentation, but clarifies that it is not establishing a proof standard that relies solely on contemporaneous documentation. As EGS suggests, and as recognized in the abstract by the ALJs, credible testimony or other forms of evidence can satisfy the burden of proof necessary to

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[82] PFD at 461 and 467.

[83] PFD at 13.

justify the reasonableness of incurred expenses. A credible witness may certainly be able to support a point and persuade an examiner without reliance on paper or electronic records. That stated, with the high speed and high memory computer capacity and storage functions available today, utilities should be able to easily store, retrieve, and present detailed contemporaneous documentation supporting claimed expense transactions. The Commission directs those utilities that have not already done so to implement some form of rational standardized contemporaneous documentation retention procedures. Accordingly, FoF 20 is modified to address the Commission's conclusions regarding contemporaneous documentation.

On a related point, a number of the topics addressed in the fuel sections of the PFD and SPFD involve, or could involve, the use of benchmarks to measure the reasonableness or prudence of a purchase or other action. The Commission notes that appropriate benchmarks are often a useful tool to measure a utility's actions, particularly in the absence of contemporaneous documentation. While benchmarks may not be necessary in a situation in which a purchase price can be compared directly to a competing bid (as in the Bidweek purchases discussion below), the Commission otherwise encourages parties to propose benchmark standards to use in evaluating utility actions and decisions in individual rate cases.

2. Long-term Gas Contracts and Purchases

The ALJs conclude that EGS failed to establish the prudence of two gas purchase contracts--the Texaco and Enercorp contracts--because of a lack of adequate contemporaneous documentation. Nevertheless, the ALJs ultimately recommend that the Commission allow EGS to recover its claimed expenses relating to purchases under these contracts.

The Commission affirms the ALJs' result but concludes that the proper analysis in this case requires an evaluation of the individual purchases made under these contracts. No party or the ALJs proposed any disallowance for purchases under the Enercorp contract because gas purchased under this contract was priced in the range of other spot purchases during the reconciliation period.[84] The Commission agrees with the ALJs that all of the Enercorp purchased gas costs should be allowed.

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[84] *Id.*

The Texaco contract is essentially an option agreement at no cost that provides EGS with the opportunity (secondary to Entergy Louisiana), but not the obligation, to purchase natural gas as needed if available. The "prudence" of such an option agreement is not the proper focus; instead the proper focus is whether the individual spot purchases under the contracts were prudent. The Commission concludes, based upon the record evidence, that purchases under the Texaco contract were prudent. The Commission also clarifies that it is not adopting the ALJs' methodology for calculating a disallowance and concludes that the record evidence does not justify any disallowance of the purchase costs incurred under the Texaco contracts. Accordingly, while affirming the ALJs' ultimate conclusion that the purchases were prudent, the Commission deletes FoF 18 and modifies FoFs 16, 17, 19, 20, 24, and 25 to conform these findings to Commission policy regarding review of fuel purchases.

3. Short-Term (Monthly or Bidweek) Gas Purchases

The ALJs recommend a system-wide disallowance of $10,540,695 attributable to purchases under short-term natural gas contracts. This recommendation is based primarily on Cities' recommendation that over $16 million in short-term purchase costs should be disallowed. The ALJs also disregarded NSST's smaller recommended disallowance of $407,675 because they concluded that Cities' "more comprehensive proposal preempts NSST's proposal."[85]

The Commission rejects the ALJs' recommendations and concludes, based on the record evidence and policy, that no disallowance will apply to the bidweek purchases. The ALJs erred in relying on Cities' case, which includes a significant flaw in its comparison of natural gas market hub index prices to the *delivered* prices actually paid by EGS. Contrary to Cities' argument, the hub index prices do not include a component to account for transportation *from* the hub to the ultimate delivery point. The parties addressed this issue in written testimony and at the hearing, but the ALJs adopted the incorrect assertion. The Commission agrees that Commission precedent requires the evaluation of a utility's fuel purchases on an individual

[85] PFD at 35.

transaction-by-transaction basis.[86] However, based on NSST's analysis, the Commission disagrees with the ALJs' conclusion that there is insufficient evidence to perform such an analysis.

This leaves NSST's recommendation to disallow $407,675 based on a comparison of prices actually paid to the price available from competing bids. In doing so, NSST could find only eight occasions in which EGS paid more for gas than was available from a competing bid. The Commission concludes that NSST's basic approach is more appropriate than Cities'. Nevertheless, the Commission also concludes that the minimal disallowance proposed by NSST is not justified given the overall dollars involved and the small number of instances in which EGS' purchase price may have exceeded an alternative bid price. Accordingly, the Commission allows EGS to recover all of its claimed bidweek natural gas purchase costs, and deletes FoFs 26, 29, 30, and 31; modifies FoF 28; and adds new FoFs 26A through 26D.

4. Recommendations Regarding Coal

a. Big Cajun Unit 3

The ALJs recommend that the Commission require EGS to show in future fuel reconciliations that it has, as appropriate (1) attempted to renegotiate the agreements(s) with Cajun Electric Power Company (Cajun) to give EGS a greater voice in operating and maintaining facilities in which EGS is a non-operator minority partner; (2) exerted pressure on Cajun to

[86] PFD at 34.

prudently operate and maintain Big Cajun Unit 3 and other plants which EGS partly owns but does not operate, and (3) exercised the full extent of its powers under the agreement(s).[87]

The Commission agrees with the ALJs' point that EGS has a continuing obligation to prudently manage its contract with Cajun, but declines to order the showings recommended by the ALJs in the absence of a finding that some form of imprudence applies to EGS' actions relative to the generating facility. There are no FoFs or CoLs in the PFD that address these recommendations, but the ALJs propose their recommended language in Ordering Paragraph 3 to the PFD. That language is deleted from the ordering paragraphs included in this Order.

b. Coal Inventory

OPC made a number of recommendations regarding EGS' practices related to coal, including requiring EGS to perform a coal stockpile survey at least once every 12 months and requiring EGS to conduct sampling of stockpile heating values.[88] The ALJs concluded that these proposals would result in inappropriate micromanagement of EGS.[89] The Commission agrees with the ALJs and therefore does not approve OPC's proposed disallowances, surveys, sampling measures, and other recommendations regarding this issue.

5. Nuclear Fuel

a. Mispositioned Fuel Bundle

The ALJs recommend disallowance of $35,576 attributable to a mispositioned nuclear fuel bundle. This mispositioned bundle resulted in a 7.8 hour delay in refueling River Bend in early 1996. Even with the delay, EGS set a record (at the time) of 39.8 days for refueling River Bend, concluded refueling well under its refueling goal of 45 days, and concluded its refueling operations much faster than either the industry median or average.

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[87] PFD at 49.

[88] PFD at 74-75.

[89] PFD at 76.

The Commission reverses the ALJs on this minor disallowance. The $35,576 disputed amount is *de minimus* in relation to a claimed nuclear fuel reconciliation expense of almost $36 million. Moreover, EGS performed admirably in refueling River Bend safely in record time. The Company certainly should not be penalized for this minor fuel bundle positioning error in the midst of much greater and cost effective accomplishments. Accordingly, the Commission deletes FoF 65 and modifies FoF 55 as contrary to the Commission's policy in support and encouragement of rapid and safe nuclear plant refueling operations.

b. <u>1977 Sale of Uranium</u>

The PFD addresses an issue involving a sale of 500,000 pounds of uranium by Gulf States Utilities (now EGS) to Florida Power & Light Company in June of 1977. Gulf States credited the profit to its shareholders. Cities argues, 20 years after the sale, that the profits should have been credited in a manner that would benefit Gulf States' (now EGS') customers. EGS counters that Cities should have raised this point years ago, and the issue is now barred by *res judicata.* The ALJs agree with EGS, concluding that *res judicata* forecloses the issue.

The Commission agrees with the result, but not necessarily with the ALJs' conclusion regarding *res judicata.* The Commission concludes instead that Gulf States/EGS did not include any portion of the uranium expense in rate base, base rates, or fuel. Thus, the Company's customers never bore the financial burdens and risks of this expense in a manner that could support a claim to recovery of the gain on the sale.[90] Accordingly, the Commission adds new FoF 74A and modifies CoL 5 to reflect the Commission's position.

c. <u>Lease Interest Costs Attributable to Nuclear Fuel Acquisition</u>

The ALJs also conclude that *res judicata* precludes the revisitation of February 1989 fuel lease notes and lease interest payments involving the acquisition, processing, and leasing of nuclear fuel for River Bend. For reasons similar to those stated above, the Commission concludes that the evidence submitted by Cities in opposition to the lease costs was not sufficient to persuade the Commission to disallow the costs. Accordingly, in addition to the lateness of

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[90] *See Public Utility Comm'n of Texas v. Gulf State Utilities Co.,* 809 S.W.2d 201, 211 (Tex. 1991).

Cities' claims, the Commission's rationale for justifying these costs requires the addition of new FoF 76A and deletion of CoL 6.

6. Calculation of Underrecovery and Surcharge

The parties agree that the PFD incorrectly attempted to take into account the effects of a fuel surcharge ordered in Docket No. 15102. By doing so, the ALJs derive a fuel surcharge for this docket of $42,230,593 (exclusive of interest). The parties note that the surcharge from Docket No. 15102 was collected during the reconciliation period subject to this docket, and therefore should not be reflected in the surcharge applicable to this docket. The Commission agrees, and concludes that the surcharge figures presented by General Counsel are the most reasonable and accurate. Accordingly, to conform the findings of fact to the preponderance of evidence, FoFs 85 and 86 are modified to reflect that the total surcharge in the current case, exclusive of other allowances authorized in this Order, is $32,507,222 ($28,620,522 principal and $3,886,700 interest).

7. Disallowances and Non-Fixed Fuel Factor Customers

The ALJs recommend that the Commission reverse or decline to follow its decision in EGS' last fuel reconciliation case (Docket No. 15102) to allocate disallowance refunds to non-fixed fuel factor (NFFF) customers. The ALJs recite eight considerations in particular for reaching this conclusion.[91] The Commission is persuaded that the Docket No. 15102 precedent is unsound and should not be followed. The Commission's distilled basis for this decision is the simple fact that NFFF customers do not pay fuel expenses through a fuel factor subject to reconciliation. Therefore, the Commission does not adopt the ALJs' detailed reasoning regarding pass-through tariffs or constitutional arguments that suggest rejection of the Docket No. 15102 precedent. To reflect the Commission's more limited policy rationale, FoF 96 and CoL 10 are modified accordingly.

8. Interim and Final Fuel Factors

[91] PFD at 135-36.

The SPFD addresses the interim and final fuel factors applicable to this docket. The ALJs recommended denial of EGS' requests for (1) an interim fuel factor, and (2) to treat TEPs and wheeling revenues as base rate items.

The TEPs and wheeling revenue issue are discussed in the Revenue Requirement section above. The Commission determines that base rate treatment of TEPs and wheeling revenues is proper because these expenses and revenues are not eligible fuel expenses. The Commission agrees with the ALJs' denial of the interim fuel factor request. In addition, the Commission modifies the final fuel factor to reflect the Commission's other decisions in this Order. Accordingly, to conform the findings and conclusions to Commission policy, the Commission adds FoF 74A, deletes FoF 96L (SFoF 12), and modifies FoFs 82B, 96K, 96M, and 96Q (SFoFs 19, 11, 13, and 17, respectively) and CoL 11E (SCoL 5).[92]

III. Rate Decreases and Refunds Arising From this Order

The base rate decreases and refunds resulting from this Order and from the Commission's final order issued in *Gulf States Utilities Company Remand of Actual Taxes Paid Issues,* Docket No. 18290, shall be segregated into two time periods. The first time period, referred to as the Historical Refund Period, is from June 1, 1996 through July 31, 1998.[93] The second time period, referred to as the Prospective Rate Decrease Period, is from August 1, 1998 through May 31, 1999.

Notwithstanding the cost allocation and rate design treatments established in this Order, for purposes of implementing refunds arising from this docket, all refunds shall be returned to base rate customer classes, and then to rate classifications within those base rate customer classes, based on (1) the current rate design for base rates in place during the period from June 1, 1996 and prior to the effective date of this Order, and (2) the relative base rate revenue collected from each of the customer classes and rate classifications during that period.

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[92] The Commission also modifies CoL 11 to reflect the correct eligible fuel expenses as provided by the ALJs in their clarifications filed on June 12 and 16, 1998.

[93] The phrase "Historical Refund Period" is an as-yet undefined period that certainly commences on June 1, 1996, and ends on the date EGS implements the prospective base rate reductions ordered in this docket. The references in this Order (including references in the ordering paragraphs and attachments) to a July 31, 1998 ending date for the Historical Refund Period and an August 1, 1998 beginning date for the "Prospective Rate Decrease

In addition, Cities and General Counsel noted on rehearing that an error exists in the Interim Order issued on July 14, 1998 and attached to this Order at Attachment A. On page 3 of the Interim Order, the Commission ruled that the interest on surcharges due to the Company shall be the applicable interest rate "approved by the Commission for customer deposits in accordance with PUC SUBST. R. 23.45(h)." This is an error and the Interim Order is hereby modified. The interest rate on surcharges due to the Company shall be the interest rate computed for *overbilling and underbilling* in accordance with PUC SUBST. R. 23.45(h).

A. Historical Refund Period

The Interim Order (Attachment A), as modified above, addresses the refund procedures applicable to the Historical Refund Period. The Commission also attaches as Attachment B a schedule that illustrates the refund and surcharge allocation procedures for both the Historical Refund Period and Prospective Rate Decrease Period (discussed further below). Except for the two $20 million lump sum refunds in August and September 1998, and the monthly $3 million payouts from October 1998 through March 1999, the numbers displayed on Attachment B are for illustrative purposes only. Because the effective date of new rates will be later than July 31, 1998, the Commission attaches Attachment B-1, which shows historical refunds as of November 30, 1998 as illustrative of the impact of this order. The numbers shown on Attachment B will change depending on when the refunds and surcharges actually appear on customers' bills. The Company shall use the allocators specified on Attachment B to allocate the refunds and surcharges.

The Commission also grants a request raised by EGS in its second motion for rehearing regarding the Commission-ordered increase in standby rates. Essentially, the refund calculations subject to Attachments A and B make the standby rate increase effective as of June 1, 1996. This increase, however, should be *prospective* only from the effective date of the new base rates in this docket. Therefore, to correct a potential situation in which EGS has over-refunded dollars related to a prospective standby rate increase without crediting EGS for any of the increased standby revenue, the Commission directs that EGS will be allowed to recoup the over-refunded standby-related revenue in the refund true-up procedures applicable to this docket.

Period" *are for illustrative purposes only* and in no way allow EGS to avoid paying all refunds that accrue through

B. Prospective Rate Decrease Period

The rate decrease ordered in this docket will continue through May 31, 1999, which results in the Prospective Rate Decrease Period (illustrative) spanning the months of August 1998 through May 1999. This base rate decrease will be offset in each of the prospective period months by a proportionate amount of the remaining AOD balance as adjusted to include interest on the remaining balance. As with the base rate-related refund in the historical period, the interest rate applicable to the remaining monthly AOD balances shall be equivalent to the overall return approved in this docket.

C. The Next Rate Case

The Commission assumes in this Order that the base rates subject to this docket are locked-in for the period June 1, 1996 through May 31, 1999. The May 31, 1999 end-date, however, is not certain, and will not be known until EGS files its next rate case. That docket will determine the effective date of the new base rates. If that effective date starts on a date prior to June 1, 1999, an issue in that next rate case docket will involve the adjustments, if any, that are necessary to close out the AOD amortization treatment ordered in this docket.

The Commission also notes that it expects the next rate case to include only revenue requirement and major rate design issues, in order that the case can be resolved expeditiously. The competitive issues, including the PBR/nuclear fuel cost issues finalized in this docket, should not be revisited in the November 1998 filing (but may be addressed in a later docket). EGS filed for a fuel factor revision on September 8, 1998 in Docket No. 19834. Requiring EGS to make another fuel factor filing as part of its November 1998 rate case would be unnecessarily duplicative of Docket No. 19834. In addition, with respect to fuel reconciliation, EGS has just gone through two back-to-back fuel reconciliations, one in Docket No. 15102, a case limited to fuel reconciliation, and the current case, a general rate case. It is appropriate to have a break before the next fuel reconciliation. Therefore, EGS is not required to file a fuel reconciliation with the November 1998 rate case, and a good cause exception to the rate case filing requirement is granted accordingly. The SOAH ALJs assigned to the next case will address the procedural issues raised by EGS. Otherwise, EGS should be prepared to address any other revenue

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the date the prospective rate decrease is implemented in this docket.

requirement and major rate design issues in the November 1998 rate case. Accordingly, FoFs 96R through 96U are added to clarify this issue.

Finally, EGS has not proposed to recover its rate case expenses or the Cities' rate case expenses in this docket. The question remained whether the Company might attempt to recover these expenses in a future docket. At the Commission's open meeting on July 10, 1998, representatives of EGS committed orally on the record that the Company will not seek to recover Cities' or its own rate case expenses in this proceeding or any future proceeding. Accordingly, a FoF 164 is modified and a new FoF 164A is added to reflect this commitment.

IV. Findings of Fact and Conclusions of Law

The section consolidates the FoFs and CoLs contained in both the PFD and SPFD, as modified in accordance with the foregoing discussion. The numbering sequence contained in the PFD is retained; the SPFD FoFs and CoLs are integrated into this sequence by placing them in the proper location and changing the SPFD number to a corresponding numbered *and* lettered designation. The designation "SFoF" refers to the findings in the Supplemental PFD. The references to "Revised PFD" refer to the corrected pages to the PFD filed by the ALJs on June 4, 1998.

A. Findings of Fact

1. Entergy Gulf States, Inc. (EGS) is an electric utility serving southeast Texas and south central Louisiana and is one of five wholly-owned operating companies of the Entergy Corporation, an investor-owned public utility holding company headquartered in New Orleans, Louisiana.

2. On November 27, 1996, EGS filed a request for approval of a proposed revision to its fixed fuel factors, along with a request for a general rate case, fuel reconciliation, and approval of a transition to competition plan.

3. To ensure uniform rates for all of its Texas customers, EGS also filed identical applications with each municipality retaining original jurisdiction over its rates. The

decisions concerning EGS' rates by the municipalities retaining original jurisdiction were appealed to the Commission and consolidated into this case.

3A. EGS agreed to make any base rate reductions ordered in this docket effective as of June 1, 1996, system-wide pursuant to an agreement with the municipalities. EGS Ex. 1 vol. 1, Application at 18 ¶ 26; GC Ex. 61.

4. On December 4, 1996, the Public Utility Commission of Texas (Commission) referred this docket to the State Office of Administrative Hearings (SOAH) and requested the assignment of an administrative law judge (ALJ).

5. EGS provided notice by publication for four weeks in newspapers having general circulation in each county of the utility's service area.

6. The Commission and SOAH provided ten days notice of the initial prehearing conference by submission of notice filed December 5, 1996 to the Texas Register and publication therein (21 Tex. Reg. 11975 (Dec. 13, 1996)).

7. The test year for the fuel reconciliation and the revenue requirement is July 1, 1995 to June 30, 1996.

8. Deleted.

9. Entergy Corporation (Entergy) is an investor-owned public utility holding company headquartered in New Orleans, Louisiana. Its five wholly owned operating companies are EGS, Entergy Arkansas, Inc. (formerly Arkansas Power & Light Co.), Entergy Louisiana, Inc. (formerly Louisiana Power & Light Co.), Entergy Mississippi, Inc. (formerly Mississippi Power & Light Co.), and Entergy New Orleans, Inc. (formerly New Orleans Public Service, Inc.), which cumulatively provide electric service to approximately 2.4 million retail customers. EGS and NOPSI also provide gas service in

Baton Rouge and New Orleans, Louisiana, to nearly 240,000 customers. The Entergy system companies provide electricity to wholesale customers as well.

Fuel Reconciliation

Heat Rate

10. EGS' 15 fossil fuel plant reconciliation period heat rates exceeded its five-year (1990-1994) average heat rate, and 11 of the plants experienced a reconciliation period heat rate higher than in any of the five previous calendar years (1990-1994).

11. EGS has not shown that the increased heat rate and increased expenses were the reasonable and necessary result of prudent changes in system dispatch or fluctuations in output due to fluctuations in demand.

12. EGS has not shown that the increased heat rate and increased expenses were the reasonable and necessary results of normal wear and tear, such as end-of-operating-cycle reduced efficiency, certain performance and capability deficiencies, or high condenser back-pressures due to unclean condensers.

13. A disallowance of $9,090,120 in fuel expenses is appropriate, based on the extent that each EGS plant exceeded its highest heat rate in any of the five previous years.

Natural Gas Expenses

14. EGS sought reconciliation of $455,023,433 in natural gas expenses.

Natural Gas Long-Term Contracts

15. EGS purchased natural gas under 11 long-term contracts during the reconciliation period. Of these, two (Texaco and Enercorp) were initiated and three expired during the reconciliation period.

16. The Texaco and Enercorp contracts provide some value (although not quantified) because of (1) their reliability (non-interruptibility) and flexibility (swing); and (2) the price

advantage over the reconciliation period of the Texaco contract relative to daily index prices and the Enercorp contract relative to monthly index prices.

17. Under the Texaco contract, Texaco is obligated to supply gas to EGS, subject to Entergy Louisiana, Inc.'s priority right to take, but EGS is not obligated to take any gas under the contract.

18. Deleted.

19. Where EGS has a right, but no obligation, to purchase gas under a contract, the proper standard is for EGS to justify the reasonableness and necessity of each purchase under such contracts.

20. No contemporaneous documentation is available to show that individual purchases under the Texaco and Enercorp contracts were prudent.

21. In the absence of contemporaneous documentation, a comparison to an appropriate benchmark is a reasonable way to determine the prudence of individual purchases.

22. The appropriate starting point for such a benchmark is a comparison of contemporaneous bids.

23. The appropriate bids for comparison are short-term daily (or average of the current day and the next day) bids.

24. The index price does not include transportation fees, Louisiana taxes, or interstate pipeline fees.

25. The record evidence does not justify any disallowance for any purchases under the Texaco or Enercorp contracts, or any other long-term contract.

Bidweek Gas Purchases - NSST's Challenge

26. Deleted.

26A. The appropriate method to evaluate a utility's fuel purchases is on an individual transaction-by-transaction basis.

26B. On eight occasions during the reconciliation period, EGS paid more that a lower-cost bid for short-term gas purchases.

26C. A utility is not required to demonstrate perfection in making fuel purchases.

26D. The record evidence in this case does not support any disallowance for short-term gas purchases.

Bidweek Gas Purchases - Cities' Challenge

27. When a utility is unable or unwilling to provide sufficient evidence to prove its prudence, it may be appropriate to resort to a benchmark for comparison.

28. In this case, EGS provided sufficient contemporaneous documentation of its bidweek gas purchase decisions; accordingly, reference to a benchmark for comparison is not necessary.

29. Deleted.

30. Deleted.

31. Deleted.

February 1996 Gas Expenses

32. A disallowance of $11,211,685 in excessive gas expenses incurred in February 1996 is appropriate.

32A. EGS failed to take reasonable precautions as to a reasonably likely event-–an increase in natural gas prices due to an arctic outbreak during the winter of 1995-96. (SFoF 21).

32B. EGS was particularly sensitive to an unusually cold weather event, because of its heavy reliance on gas and significant scheduled outages. (SFoF 22).

32C. Because of this sensitivity to gas price volatility, EGS would have been prudent to prepare for adverse weather and increased gas prices by increasing its level of gas storage, preparing units to burn fuel oil, making an advance (forward) gas or power purchase, increasing bidweek purchase contract volume, and increasing nominations under long term contracts. (SFoF 23).

32D. EGS exacerbated the negative consequences of its lack of preparation by reacting inappropriately both immediately before and during the arctic outbreak. EGS could have minimized the ill effects by obtaining and using weather forecasts more wisely, increasing purchases under bidweek contracts and long term contracts, buying the lowest-priced available purchased power, withdrawing more gas from the Spindletop storage facility, burning more fuel oil, and managing load by interrupting interruptible service customers. (SFoF 24).

32E. The imprudence of EGS' actions before and during early February 1996 was confirmed by comparison to the gas costs of EGS' neighboring utilities, Houston Lighting and Power Company (HL&P) and Central Power & Light Company (CP&L), during the same time frame. (SFoF 25).

32F. It is reasonable and appropriate to disallow EGS' swing (spot) gas purchases during the first 12 days of February 1996 to the extent they exceeded $3/MMBtu, *i.e.*, $11,211,685. (SFoF 26).

Fuel Oil Expenses

33. EGS requested reconciliation of and has shown that it prudently incurred $846,983 in fuel oil expenses.

Coal Expenses

34. EGS requested reconciliation of and has shown that it prudently incurred $52,474,427 in coal expenses.

Coal Unit Outages

35. EGS' two coal units each experienced a planned outage during the reconciliation period.

Nelson 6

36. EGS planned a 91-day outage at its Nelson Plant Unit 6. The outage was extended by five days to 96 days due to a delay in the receipt of duct work. The purpose of this outage was to convert the electrostatic precipitator from the hot side to the cold side and to overhaul the turbine and generator. These actions were intended to avoid future outages to clean the precipitator about every three months.

37. As to Nelson Unit 6, EGS saved $1.2 million in coal transportation costs by accelerating the outage timing and the extension of the outage did not result from any imprudence on the part of EGS.

Big Cajun II Unit 3

38. Big Cajun II Unit 3, was scheduled for a 56 day outage, but that outage was extended by 7 days (to 63 days).

39. As to Big Cajun II Unit 3, it is reasonable to expect that testing new controls may take longer than originally expected, and the outage extension was not reasonably preventable.

Coal Inventory Accounting

40. In April 1994, EGS converted from a "manual" (presumably non-computerized) accounting system to the computerized ARLIS accounting system.

41. On January 1, 1995, EGS converted its coal accounting from tons to MMBtu and its coal cost calculations from last-in-first-out (LIFO) to average cost. In October 1995, a flyover survey revealed that physical inventory was only 54% of book inventory. EGS' accounting records indicated that Nelson Unit 6 had almost twice as much coal as it actually had. A base elevation adjustment was made so that the sunken (but usable) 35,064 tons (574,666 MMBtu) would be included in the physical inventory numbers shown above.

42. After the October 1995 flyover survey, EGS concluded that it should implement the book inventory adjustment over 12 months rather than charge the entire amount to eligible fuel expenses as a lump sum in one month.

43. In June 1996, EGS revised its plant maintenance program as follows to increase coal measurement accuracy: scales are electronically calibrated weekly, test chains are calibrated weekly, and material weight tests are scheduled biannually.

44. Any coal inventory disallowance in this case should be based on the extent of the book/physical inventory discrepancy.

45. Coal measurement improvements toward the end of this fuel reconciliation period should significantly diminish the possibility and degree of future book/physical inventory discrepancies.

46. After having improperly included in reconcilable fuel expense the cost of these 60,000 or so tons of buffer coal, during the manual-to-ARLIS accounting conversion, EGS appropriately set out to remove those costs from book inventory, and thus from eligible fuel expense.

47. The evidence does not permit a determination as to whether the ARLIS reports or the burn sheets were in fact the "official accounting records" for the months April-December 1994.

48. EGS/Entergy fuel accountants had or should have had the burn sheets available, either to directly enable proper "billing" to rate payers, or at least to confirm the information provided by ARLIS.

49. Book inventory accuracy should be confirmed by frequent surveys, at least once per year.

50. The October 1993-October 1995 period included a number of those circumstances under which a survey should have been conducted more than once a year. In that time period, EGS knew that it was undergoing three major accounting conversions (manual to ARLIS, tons to MMBtu, and LIFO to average cost) and that it had coal measurement problems (nonfunctional scales and insufficient scale calibration frequency, at least). EGS' survey delay compounded EGS' other (measurement and accounting) errors by allowing the book/physical inventory discrepancy to remain uncorrected, perhaps even to grow. The large (on a snapshot basis) measurement error and the improper inclusion of 60,000 tons of buffer coal during the April 1994 manual-to-ARLIS conversion are textbook examples of reasons to increase, not decrease, the survey frequency.

51. The evidence does not show that EGS has wasted or lost any stockpile coal, thus no disallowance is appropriate with regard to the Nelson 6 inventory accounting problems.

52. Cajun does not maintain its own inventory records in MMBtus. Cajun has not historically obtained stockpile heating value analyses along with its physical stockpile surveys. During the reconciliation period, Cajun had flyover surveys conducted in the fall 1995 and spring 1996, but it appears neither survey included a heating value analysis so as to enable an accurate assessment of the number of MMBtu in that stockpile.

53. EGS' reliance on Cajun's tonnage reports appears unwise, given EGS' accounting in MMBtu for its share of the Big Cajun II Unit 3 stockpile. However, no disallowance has been proposed, and no disallowance is appropriate.

Nuclear Fuel Expenses

54. EGS requested reconciliation of $35,778,352 in nuclear fuel expenses for the River Bend nuclear generating unit.

55. It is reasonable and appropriate to disallow $693,380 related to EGS' fuel engineering services costs, for EGS' failure to satisfy the burden of proof.

Nuclear Unit Forced Outage FO-95-01

56. On December 19, 1995, River Bend entered Forced Outage FO-95-01, which lasted about 2.3 days and was the result of false instrument indications that damaging cavitation conditions were present. Those false indications automatically triggered a shutdown or trip of the "B" recirculation pump and a shift from high to low speed for the "A" recirculation pump. Reactor operators then manually scrammed the reactor and shut down the plant.

57. Movement of a cable (with a slightly loose termination) could change the signal in the cable by about five degrees, which might have been enough to induce a false cavitation warning under the operating conditions at that time.

58. Those operating conditions included the following: (1) River Bend's planned "coastdown" in power (as it neared the end of the operating cycle) had the side effect of reducing vessel pressure; (2) EGS had intentionally reduced vessel pressure in an effort to reduce unidentified leakage detected inside the drywell; and (3) the set point on the "B" pump cavitation protection instrumentation had drifted upward by two degrees. These three factors and the loose cable connection combined to cause a false indication of damaging cavitation conditions, which led to the recirculation pump trip and the manual plant shutdown.

59. The first and second recirculation pump trips were not reasonably preventable and therefore no disallowance is appropriate in relation to Forced Outage FO-95-01.

Nuclear Unit Refueling Outage RF-6

60. River Bend Refueling Outage RF-6, which began January 4, 1996, and ended February 13, 1996, set a record (at the time) for the shortest refueling outage ever performed at any Entergy nuclear plant. EGS had set both a 45-day "goal" (which was itself a reduction from an earlier 60-day estimate) and a 32.9-day "target" as a "planning tool" for the River Bend Outage Management Department. Refueling Outage RF-6 lasted just under 40 days.

61. The only NRC-cited violation that affected the outage was a mispositioned fuel bundle, which caused 7.8 hours of delay.

62. The most useful benchmark for this issue is the 49-day industry-median outage length for BWRs in the relevant time period.

63. The RF-6 duration of 39.8 days is well under the relevant industry median of 49 days.

64. The mispositioned fuel bundle raises heightened concern because it (along with other errors) triggered an NRC violation and a meeting with the NRC.

65. Deleted.

66. As to the entry into Refueling Outage RF-6 related to the second recirculation pump trip, EGS' actions were not imprudent, for the same reasons cited above regarding Forced Outage FO-95-01.

67. The turbine vibration was not an instance of imprudence and does not warrant a disallowance.

Nuclear Unit Forced Outage FO-96-01

68. On June 6, 1996, the River Bend plant experienced a rapid decrease in turbine load along with a rapid increase in reactor power and pressure. To be safe and to allow for investigation, the operators manually scrammed the reactor. The outage lasted about 8.9 days. The EGS investigators determined that reactor pressure had risen because one of the turbine stop valves and the intercept valves had closed, due to failure of two redundant power supplies, which failure was attributed to an overvoltage condition and a defective blocking diode in one power supply, which then apparently prevented the other power supply from picking up the load.

69. No reasonable quality assurance program would have detected the defective diode that caused the power supply failure.

70. After replacing the defective part, the power supplies again worked correctly. The defective diode was not discoverable despite a reasonable level of quality assurance at both the power supply vendor's facility and at River Bend. Thus EGS was not imprudent with respect to the power supply failure, and no disallowance is appropriate.

71. EGS was not imprudent with respect to the air handler fan bearings faulty installation and repair work which extended Forced Outage FO-96-01; thus, no disallowance is appropriate.

Nuclear Fuel: 1977 Uranium Sale

72. In June 1977, EGS' predecessor Gulf States Utilities, Inc. (GSU) sold about 500,000 pounds of uranium concentrate to Florida Power & Light Company. GSU credited the profit to its shareholders.

73. GSU sold the uranium to gain an immediate source of cash and to have more flexibility in the timing of GSU's next uranium financing.

74. The 1977 uranium sale was litigated in GSU's last fuel reconciliation case.

74A. No portion of the original cost of or carrying charges for the uranium concentrate were ever placed in rate base and ratepayers never bore the burdens or risks associated with this item.

Nuclear Fuel: Lease Interest

75. In February 1989, GSU entered into a nuclear fuel lease with River Bend Fuel Services, Inc. (RBFS), a corporation whose sole purpose is to acquire nuclear fuel, process the fuel (via conversion, enrichment, and fabrication), and lease the fuel to EGS for use at the River Bend station. RBFS finances the acquisition and processing of nuclear fuel through the issuance of intermediate term notes and through loans from certain financial lending institutions.

76. All the information Mr. Hubbard needed to review the 1989 notes and propose a disallowance was available in previous dockets, and Mr. Hubbard did not need the amortization breakdown to review the 1989 notes and propose a disallowance.

76A. The evidence in the record does not support any disallowance of nuclear fuel lease costs.

Nuclear Fuel: Engineering Services

77. Engineering services accounted for $772,623 (2.2%) of EGS' eligible nuclear fuel expenses in this reconciliation period. Those expenses were related to nuclear fuel in process and to batch numbers 5-9.

78. The engineering services expenses for batches 7 and 8 were much higher (about 1000% higher) than for batches 6 and 9.

79. EGS presented no additional explanation or extraneous documentary evidence for its unsubstantiated conclusory assertion that batches 6 and 9 had a very low percentage of their overall costs charged to in-house design.

80. EGS' claim that it changed accounting methods during batch 9 to achieve Entergy system uniformity was an unsubstantiated conclusory assertion without extraneous documentary evidence or additional explanation. It also fails to explain why the cost for batch 6 was so relatively low.

81. EGS has failed to satisfy its burden of proof to show that $693,380 of its nuclear fuel engineering services expenses were prudently incurred, and that amount should therefore be disallowed.

Wheeling Revenues and Account 565 Expenses

82. EGS requested a good cause exception to the fuel rule's requirement that wheeling revenues and Account 565 expenses be included in eligible fuel expenses. As determined by the Commission in *Application of Southwestern Electric Power Company For Reconciliation of Fuel Costs, Surcharges of Fuel Cost Under-Recoveries, and Related Relief*, Docket No. 17460 (May 17, 1998) (SWEPCO), these expenses and revenues are not eligible fuel expenses. Thus, wheeling revenues and Account 565 expenses are not treated as reconcilable for this reconciliation period.

82A. EGS showed that, during the last rate case (Docket No. 12852), its wheeling (company service) expenses were placed in base rates. To now subtract wheeling (company service and access service) revenues from the fuel factor calculation (without adding wheeling expenses) would therefore be a double dip against EGS (*i.e.*, EGS would be treated as if it had received payment from not only wheeling customers but also retail customers -- virtually double the amount of wheeling revenues it actually received) unless base rates were simultaneously adjusted to exclude wheeling expenses. That simultaneous adjustment would require the onerous, time-consuming modification of the cost-of-service studies and allocation factors from the last rate case in order to set new base rates coincident with the implementation of the Phase I interim fuel factor. Inconsistent regulatory treatment (the double dip) would be unfair, and an onerous simultaneous retroactive base rate adjustment would be unwise; this third argument therefore strongly tends to show good cause for an exception as to the fuel reconciliation. (SFoF 18).

82B. Therefore, as to the fuel reconciliation, EGS' wheeling revenues and Account 565 expenses are not eligible fuel expenses. (SFoF 19).

82C. Cities failed to show good cause to deviate from the fuel rule so as to treat MSS-1 expenses as reconcilable, because: (1) MSS-1 expenses do not include any fuel expense component; and (2) elimination of regulatory lag does not justify expanding the scope of the fuel rule to include MSS-1 expenses, because regulatory lag affects all non-reconcilable (base rate) expenses, and MSS-1 expenses have not been shown to differ from any other non-reconcilable expense so as to justify reconcilable treatment. (SFoF 20).

Purchased Power Expenses

83. EGS requested reconciliation of and showed that it prudently incurred purchased power costs of $199,521,206.48.

84. EGS' $199,521,206.48 in purchased power and affiliate expenses were reasonable and necessary, and the prices charged by its supplying affiliates were reasonable and necessary and no higher than the prices charged by the supplying affiliate to its other affiliates or divisions or to unaffiliated persons or corporations for the same item or class of items.

Calculation of Surcharge and Interest Collection

85. EGS' cumulative fuel under-recovery balance as of June 30, 1996 was $48,308,092 (including interest and the remaining underrecovery balance (including interest) for the Docket No. 15102 reconciliation period). After reducing the amount shown above to reflect (1) the disallowances in Docket No. 15102, (2) the surcharge of the remaining underrecovery balance from Docket No. 15102, and (3) the disallowances in this docket,

the underrecovery balance, if surcharged in one month (August 1998 assumed), as required by P.U.C. SUBST. R. 23.23(b)(3)(C), is $32,507,222 ($28,620,522 principal plus $3,886,700 interest).

86. Because the significant base rate reductions in this case, it is appropriate to use the total surcharge amount to offset a portion of the base rate refunds during the Historical Refund Period for the fixed fuel factor customers.

87. It is not appropriate to adopt EGS' proposal that the surcharge either: (a) not incorporate interest due beyond the start of the surcharge period; or (b) if surcharge period interest must be included in the surcharge, then only incorporate interest for the first 11 of the 12 surcharge months.

Disallowances and Non-Fixed Fuel Factor Customers

88. In EGS' last fuel reconciliation case (Docket No. 15102), the Commission ordered EGS to allocate a portion of certain disallowances to EGS' Texas Non-Fixed Fuel Factor (NFFF) customers.

89. General Counsel and EGS have asked the Commission to reverse or decline to follow its Docket No. 15102 decision to allocate disallowance refunds to NFFF customers.

90. Certain EGS customers specifically requested the rate structure of certain NFFF rates and participated in the development of the rate structure of certain NFFF rates.

91. NFFF customers have only recently requested inclusion in the disallowance refund distribution pool.

92. Certain NFFF customers (including EAPS customers) can choose not to accept power in those hours when they learn the price of power is high.

93. NFFF customers' exclusion from disallowances benefits was balanced or outweighed by the significant overall rate reductions offered by NFFF rates.

94. Certain NFFF rates do not in fact include a "fuel" expense.

95. NFFF rates do not include a "fuel factor," despite the name "non-fixed fuel factor," because the NFFF energy charges do not "pass costs through" to the NFFF customers, but only approximate fuel expenses, and therefore the "fuel" portion of the energy charge is not reconcilable.

96. NFFF expenses and revenues should not be included in fuel-reconciliation calculations. NFFF customers should not participate in reconciliation disallowances.

Interim Fuel Factor

96A. The portions of EGS' application and testimony regarding its proposed interim revision to the fixed fuel factor are not reasonably comprehensible -- *i.e.*, the lack of useful summaries, calculations, and tables made the application unnecessarily difficult to evaluate. (SFoF 1).

96B. EGS failed to supplement its application so as to provide the interim fuel factor eligible fuel expense components of purchased power expenses and off-system sales revenues for the months of March-June 1998. (SFoF 2).

96C. EGS' slowness in providing discovery responses aggravated the difficulty of evaluating the application. (SFoF 3).

96D. EGS' proposed interim fuel factor would have been in effect for such a short period of time that its consideration and implementation would be an inappropriate use of Commission resources and could needlessly complicate later Commission determinations. (SFoF 4).

Final Fuel Factor

Nuclear Fuel Costs

96E. EGS' nuclear fuel expense estimate, as modified by General Counsel, was based on ambitious operating assumptions, such as 30-day outages every 18 months and a 95% capacity factor between refueling outages, along with dollar considerations such as the level and book value of existing inventories, financing costs, spent fuel disposal fees, decommissioning and decontamination fees, and anticipated contract and market prices associated with procurement of uranium concentrates, conversion, enrichment, and fabrication. (SFoF 5).

96F. EGS' and General Counsel's nuclear fuel estimate of $30,874,211 is the most reasonable proposal, because it better indicates EGS' likely expenses than does Cities' benchmark. (SFoF 6).

Good Cause Exception for Wheeling Revenues and Account 565 Expenses

96G. EGS asked to be excused from the fuel rule's P.U.C. SUBST. R. 23.23(b)(2)(B) requirement that "eligible fuel expenses" include expenses recorded in Account 565 of the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts and revenues from wheeling transactions (comprising revenues from Access Service and Company Service). (SFoF 7).

96H. In the fuel reconciliation period for this case, the only items recorded by EGS in Account 565 are transmission equalization expenses paid pursuant to Service Schedule MSS-2 of the Entergy Service Agreement (ESA). Under the MSS-2 expense/revenue formula, EGS and other "short" (*i.e.*, relatively transmission-deficient) Entergy operating companies (EOCs) effectively pay into a pool from which the "long" (*i.e.*, relatively transmission-plentiful) EOCs draw; this formula is intended to equitably distribute the ownership costs of certain transmission facilities (mostly high-voltage (230 kV)) in the Entergy System. (SFoF 8).

96I. "Access service" is transmission service provided by the Entergy System (not EGS) to wholesale customers under an open access transmission tariff filed with the FERC. Access service revenues are received at the Entergy System level and are allocated to the various Entergy operating companies in proportion to each company's load. In the fuel reconciliation period, EGS received about $2.6 million in access service revenues on a total company basis. (SFoF 9).

96J. "Company service" is transmission service provided by EGS (not the Entergy System) to several wholesale customers which have been directly connected to EGS' transmission system for many years; current customers include Cajun Electric Power Cooperative, Inc., Sam Rayburn G&T, Inc., Sam Rayburn Municipal Power Agency, Lafayette Utility System, and Louisiana Energy and Power Authority. In the fuel reconciliation period, EGS received about $33.5 million in adjusted company service revenues. (SFoF 10).

96K. EGS' evidence that these expenses/revenues are demand-related and are not variable shows that they are not eligible fuel expenses under the reasoning in SWEPCO. (SFoF 11).

96L. Deleted. (SFoF 12).

96M. Therefore, as to the final fuel factor, EGS' wheeling revenues and Account 565 expenses are not eligible fuel expenses as determined by the Commission in SWEPCO and should not be treated as reconcilable fuel expenses. (SFoF 13).

96N. The FERC has approved the relevant parts of the ESA as amended to reflect the inclusion of EGS. In Opinion No. 385, the FERC expressly accepted an amendment to the ESA which added Gulf States to the ESA as an operating subsidiary. EGS' MSS-2 expenses are therefore mandated by the FERC. (SFoF 14).

Good Cause Exception for MSS-1 Expenses

96O. Cities asked the Commission to disallow most of (if not all of) EGS' MSS-1 expenses, whether from base rates, where EGS has proposed their inclusion, or from the reconcilable fuel expenses used to calculate the fixed fuel factor, or else to grant a good cause exception to the fuel rule for EGS' MSS-1 expenses in order to eliminate the regulatory lag from timing differences between a FERC ordered revision in the System Agreement and a PUCT decision in a subsequent EGS base rate case. (SFoF 15).

96P. Cities failed to show good cause to deviate from the fuel rule so as to treat MSS-1 expenses as reconcilable, because: (1) MSS-1 expenses do not include any fuel expense component; and (2) elimination of regulatory lag does not justify expanding the scope of the fuel rule to include MSS-1 expenses, because regulatory lag affects all non-reconcilable (base rate) expenses, and MSS-1 expenses have not been shown to differ from any other non-reconcilable expense so as to justify reconcilable treatment. (SFoF 16).

Calculation of the Final Fuel Factor

96Q. The appropriate Texas retail fixed fuel factor is shown on Commission Schedule KP-Fuel/1. (SFoF 17).

Future Fuel Filings

96R. In order that EGS' November 1998 rate case can be resolved expeditiously, the case should be limited to revenue requirement and rate design issues.

96S. EGS filed for a fuel factor revision on September 8, 1998 in Docket No. 19834. Requiring EGS to make another fuel factor filing as part of its November 1998 rate case would be unnecessarily duplicative of Docket No. 19834.

96T. With respect to fuel reconciliation, EGS has just gone through two back-to-back fuel reconciliations, one in Docket No. 15102, a case limited to fuel reconciliation, and the current case, a general rate case. It is appropriate to have a break before the next fuel reconciliation.

96U. Based on FoFs 96R through 96T, good cause exists to waive the requirements for EGS to file a new fuel factor and fuel reconciliation as part of its November 1998 rate case.

Revenue Requirements

Invested Capital

97. EGS' appropriate level of invested capital is reflected in Commission Schedule IV.

Capital Additions

98. Capital addition costs for maintaining the River Bend Nuclear Plant during the test year were within the range of costs experienced at the plant in prior years.

99. All capital additions expenditures are directly billed, not allocated, from Entergy Operations, Inc. (EOI) to EGS.

100. The net of capital additions and capital retirements to the River Bend plant since the Company's last rate case in the amount of $11.8 million benefited ratepayers; the costs are reasonable and necessary and no higher than EOI would charge to other nuclear affiliates for the same or similar service.

101. EGS' capital additions expenditure for its fossil generation plant during the test year in the amount of $11,411,305 is an appropriate increase to rate base.

102. EGS' requested $2,134,558,000 represents an appropriate level of transmission and distribution (T&D) plant in rate base.

Accumulated Depreciation

103. EGS' appropriate level of accumulated depreciation is reflected in Commission Schedule IV. Accumulated depreciation reflects denial of EGS' request to include

certain plant in rate base as plant held for future use (PHFU) as well as treatment of the gain on Neches 7.

Gain on Neches 7

104. The gain on Neches 7 in the amount of $8,719,000 should be amortized over a five-year period beginning June 1996, with a true-up established beginning with the rate year of the November 1998 rate case.

Accumulated Deferred Federal Income Taxes (ADIT)

105. A one-time accounting change related to the last 11 days of 1992 increased Entergy's revenues to the benefit of its shareholders. Therefore, ADIT related to those unbilled revenues should not be included in rate base.

106. EGS included $42,163,843 in net operating losses (NOLs) in rate base. As discussed at §V.D.2. of the PFD, this amount should be removed from rate base.

107. Accumulated deferred income tax related to alternative minimum taxes (AMT) in the amount of $38,965,455 should be removed from rate base as discussed at §V.D.3. of the PFD.

107A. Accumulated deferred income tax of $41,269,000 related to the EGS accounting order deferrals should be removed from ADIT. The $41,269,000 is considered in the overall treatment of accounting order deferrals as discussed in Section II.A.1 of this Order.

108. River Bend Unit 2 cancellation costs are not included in rate base. Therefore the ADIT associated with this canceled plant is not included in rate base.

109. Accumulated deferred income tax should be increased for the accrual adjustment posted after test-year end to adjust the Company's 1995 tax accrual to the 1995 tax return.

110. EGS' appropriate ADIT is reflected on Commission Schedule IV.

Plant Held for Future Use

111. EGS does not have a definite plan to return Neches Station Units 4, 5, 6 and 8 and Louisiana Station 2, Units 7, 8, and 9, Right-of-Way 803, and five acres adjacent to the Orange substation to used and useful status within ten years in order to justify requiring ratepayers to begin paying for these plants in rate base as PHFU.

112. EGS' plan for these plants recognizes that they would be used only about ten percent of their capacity and only during peak times. Such minimal use should be considered in an integrated resource plan (IRP) proceeding to determine whether it is a reasonable alternative to another power source or is economically justified.

113. The costs surrounding return of these plants to rate base have not been subjected to a solicitation under PURA § 34.051, which requires that a resource solicitation be conducted under the utility's preliminary IRP. EGS has no preliminary IRP which would have taken into account such things as present and projected reduction in the demand for energy as a result of conservation and energy efficiency in various customer classes (PURA § 34.024(a)(2)); the amount and operational characteristics of additional capacity needed; the types of viable supply-side resources to meet that need; and the range of probable costs and many other inquiries dictated by PURA § 34.024. EGS should engage in the IRP process and fulfill the requirements of PURA § 34.021-34.024 before the Neches and Louisiana plants are put in rate base as PHFU.

113A. Because of advancing competition in the wholesale market and recent amendments to state law, the Commission will not follow the PHFU standard or any standard that anticipates recovery of new or mothballed generation plant investment through rate base. Instead, utilities are on notice that they should acquire new generation capacity from non-utility suppliers through the IRP process.

Cash Working Capital

114. EGS' appropriate level of cash working capital is reflected in Commission Schedule IV. Adjustments to EGS' requested cash working capital reasonably include:

a. Recognizing vacation time as a separate component of payroll to account for the lag between when the employee earns the vacation time and when the Company pays for it in salary expense;

b. Adjusting "Other O&M Expenses Over $100,000" and "$50,000 to $100,000" to recognize that the service date for medical costs is the date medical treatment was provided and the lag for Thrift Plan payments is based not on the employees' one-year employment period; and

c. Adjusting SFAS 106 regarding OPEBs.

Fuel Inventories

115. A reasonable level of coal inventory is $8,902,457, which represents approximately a 35-day supply of coal at each plant: Nelson 6 (385 megawatts) and Big Cajun II, Unit 3 (227 megawatts).

116. EGS' natural gas inventory working capital allowance of $8,542,533 is reasonable.

117. A reasonable level of fuel oil working capital in rate base is $5,110,085.

117A. An adjustment to remove $4,659,033 related to EGS' No. 6 fuel oil supply shall not be made because the record demonstrates that such fuel inventories may be used and useful. In this case, the existence of these fuel inventories supported a related disallowance of fuel expense because No. 6 fuel was not burned.

Materials and Supplies Inventories

118. A reasonable level of materials and supplies inventory is $88,527,930.

Deferred Sales Tax on Coal Cars

119. It is reasonable to include in rate base EGS' test-year-end balance of $291,000 as deferred sales tax or coal cars.

Property Insurance Reserve Balance

120. The reasonable and necessary reserve balance in rate base for property insurance should be ($15,572,000).

Other Adjustments to Invested Capital

121. Based on an amortization period ending January 31, 2000, the test year amortization expense for deferred financing costs would increase by $5,903,700, and amortization expense for property cancellation loss for River Bend 2 would decrease by $1,365,396, for a net increase in test year amortization of $4,538,304.

122. No expenditures necessary to produce cost savings related to the merger between EGS and Entergy Corporation should be reflected in rate base consistent with the decision to disallow all such costs.

123. From April 1994 through the end of the test year, June 30, 1996, EGS collected $36,205,679 on a total Company basis for post-retirement expenses other than pensions (OPEBs). This amount should not be reduced by EGS' OPEB trust funds, as EGS has not had access to the funds with which to fund rate base.

124. The following are appropriate adjustments to EGS' requested level of invested capital:

Account	13 Mo. Avg.	Adjustment	Total Level
Injuries and Damages	($5,543,000)	$643,000	($4,899,000)
Coal Car Maint. Reserve	($4,071,000)	($91,000)	($4,162,000)
Customer Deposits	($21,510,000)	($860,000)	($22,370,000)
Contractor Retainage	($455,000)	11,000	($444,000)

Cost of Capital

125. EGS' cost of capital should be based on a capital structure consisting of 48.06% long-term debt, 2.16% QUIPS, 6.52% preferred stock, and 43.26% common equity.

126. A reasonable cost of long-term debt is 8.51% and of preferred stock is 8.32%.

127. EGS' reasonable cost of quarterly income preferred securities (QUIPS) is its May 1997 embedded cost of 9.07%.

128. A reasonable range return on equity for EGS is 9.65-13.94%.

128A. A reasonable, specific return on equity for EGS is 11.7%.

128B. Based on the Commission's decision in *Entergy Gulf States, Inc. Service Quality Issues (Severed from Docket No. 16705),* Docket No. 18249, EGS' return on equity established in this docket (Docket No. 16705) is reduced by 60 basis points to 11.1% for the period June 1, 1996 through May 12, 1998. Also in accordance with Docket No. 18249, EGS' return on equity is reduced by 30 basis points from 11.7% to 11.4% from May 13, 1998 through the remainder of the period in which the rates subject to this docket are in effect.

129. EGS' cost of equity is properly determined by use of both a constant growth and a multi-stage non-constant discounted cash flow (DCF) analysis. The multi-stage non-constant DCF analysis is a reliable model for projecting dividend payouts and future growth. A constant-growth DCF analysis that captures investor expectations has value. Using two types of analyses more closely resembles the balance employed by the Commission in Docket No. 14965.

130. Deleted.

131. Deleted.

132. Deleted.

133. A risk premium calculation is an appropriate check on the DCF analysis, to assess the risks and long-term effects of deregulation on the utility industry.

134. Because all demand side management (DSM) expenses, ESI affiliate expenses, and EOI affiliate expenses not direct-billed are disallowed, it is not necessary to adjust cost of equity to account for these issues in this docket. The Commission however, is not precluded from making such adjustments in a future docket, if appropriate.

135. The appropriate weighted overall cost of capital for the period June 1, 1996 through May 12, 1998 is 9.63%. The appropriate weighted overall cost of capital for the period from May 13, 1998 through the remainder of the period in which the rates in this docket are in effect is 9.76% as reflected on Commission Schedule IV.

Cost of Service

136. EGS' reasonable and necessary cost of service, determined in accordance with this Order, is set forth in Commission Schedule I.

Operations and Maintenance Expense

137. EGS' reasonable and necessary operations and maintenance expense is set forth in Commission Schedule II.

Salaries and Wages

138. Due to declining employee rolls since test-year end and related declining costs, it is appropriate to use the most recent data evidenced in the record to calculate salary expense. A post-test-year adjustment should be made to bring payroll cost adjustments up to April 1997 levels. To capture all appropriate attendant impacts, that adjustment should include the adjustments made by EGS in its rebuttal testimony, with further changes as follows. A reduction should be made to salary expenses of $116,216 to disallow employee activity costs relating to non-business activities, such as employee

picnics, parties, lunches, dinners, and awards because these activities provide no benefit to ratepayers and are not necessary to provide utility service. In addition, the labor costs associated with employee time spent during normal business hours on outside organizations that are unrelated to the provision of service to customers should be removed. Costs related to meter reading should reflect 19 readers, and contractor expense should be adjusted, all as discussed at §VII.A.1. of the PFD.

139. It is reasonable to include in cost of service $2,997,044 in incentive compensation paid during the test year.

139A. The amount of $441,000 associated with advertising to promote electricity usage should be disallowed as consistent with EGS' adjustments.

139B. The amount of $445,000 relating to a River Bend Outage accrual should be disallowed to be consistent with other EGS adjustments.

139C. The amount of $646,517 relating to ESI affiliate expenses should also be disallowed to be consistent with the determination that EGS has not met its burden of proof relating to ESI affiliate expenses.

140. EGS' base salaries are competitive with the market, as are the incentive payments. This variable portion of compensation thus expands and contracts with the degree to which employees attain the performance goals that have been established by the utility. Such payment plans could be valuable tools in managing budgets and at the same time evoking the best work from employees. EGS' total compensation package costs are reasonable when compared with other utilities.

141. The reasonable and necessary payroll expense for EGS is reflected in attached Commission Schedule II.

Employee Pensions and Benefits

142. Total electric pension expense should reflect a 3.5% assumed salary escalation factor, an eight percent discount rate, and an adjustment to reflect the declining employee levels through January 1997.

143. EGS' reasonable and necessary pension expense through January 1997 is ($3,161,011). (*See* Revised PFD.)

144. Post-retirement benefits other than pension should be $8,800,267 for total electric. This includes a medical cost trend rate of 7.9%, an eight percent discount rate, and employee levels through January 1997. It is not reasonable to permit a utility to recover estimated costs that exceed by any large degree the actual costs experienced in the test year. The $8.8 million level of expense reasonably approximates EGS' test year OPEB expense.

Production Operation and Maintenance Expense

145. EGS included $136,327,381 in production O&M expense, of which $51,491,665 relates to fossil plants. Production O&M expense for its Big Cajun II Unit 3 plant should be $6,428,935, which amounts to a $5,921,024 reduction from EGS' requested O&M expense for this plant. Using EGS' revised figures based on the FERC Form 1 methodology achieves a reasonable total fossil plant O&M expense of $45,570,641.

Insurance Expense

146. EGS' reasonable insurance expense is $1,651,321 per year for current losses. With regard to current losses, EGS should accrue only enough each year to cover typical storm damage. (*See* Revised PFD.)

147. Any reduction to the reserve fund occurring after the test year should not be considered in this case because EGS did not prove a reasonable post-test-year level for its existing reserve fund or that the amount expended in 1997 to reduce the fund was prudent or appropriate. Reserve fund levels following the test year in this case can be addressed in EGS' November 1998 rate filing when all parties will have the opportunity to evaluate the reasonableness of changes to the insurance reserve fund.

Affiliate Expenses

148. Under PURA § 11.003(2), a utility's affiliates include any entity owning five percent or more of a utility and any entity in which the holding company has a five percent ownership interest. Accordingly, Entergy Service, Inc. (ESI) and Entergy Operations, Inc. (EOI), subsidiaries of Entergy Corporation, are EGS' affiliates. Entergy Services, Inc. provides numerous services ranging from administrative functions to providing fuel supplies to Entergy's various affiliates. Entergy Operations, Inc. is responsible for the management, operation, and support of the five nuclear generating units owned by the Entergy operating companies.

149. EGS provided evidence of ESI expenses based on the total of all expenses charged. Neither proof by an aggregate finding as to total expenses nor total expenses for that affiliate is viable in this docket--because so many services are provided by ESI, the quantity and diversity of these costs is enormous and involve thousands of items billed during the test-year period. For this reason, EGS must provide evidence of the reasonableness and necessity of its affiliate expense in strict compliance with Section 36.058 of PURA. That is, it must provide evidence supporting the reasonableness and necessity of these expenses by class of costs. It failed to do this.

150. Furthermore, independent evidence must be provided in order to meet the statutory requirement to develop findings of fact based on an item or class of items basis. EGS' direct case for ESI expenses in this docket includes no studies, no supporting evidence of non-duplication, no comparison to alternative providers, no evidence of costs to EGS on a stand-alone basis.

151. The evidence EGS provided in its direct case does not provide a means for the Commission to determine the reasonableness and necessity of ESI affiliate charges as required under PURA § 36.058. The Commission determined, on appeal of the Administrative Law Judge's Order Nos. 124, 143, and 144, that it is appropriate to direct judgment against the utility when its direct case fails to meet the required level of proof.

152. To determine the reasonableness of the ESI expenses, EGS directed the fact finder to the scope statements contained in EGS Ex. 91 at LEB-4c. Because those items are not arranged by class and no underlying evidence is included to support the reasonableness or necessity of the items by class, the only way for the Commission to make an independent evaluation of these costs is by looking at each item. Because of the nature and volume of items, such evaluation is impossible. No evidence exists in the record to support findings for each affiliate item.

153. While it may be possible to find the reasonableness and necessity of certain limited items addressed in EGS' testimony regarding ESI affiliate expenses, most costs remain unaddressed on an individual or class of costs basis. Furthermore, ESI bills EGS at its costs of providing the service, but EGS did not evaluate whether the prices ESI charged to EGS were higher than the price it charged other Entergy subsidiaries for the same or similar service. Evidence indicating that ESI bills at its costs is generally not sufficient to

show that all affiliates therefore are billed the same for similar services when there is no evidence regarding what ESI actually charge affiliates other than EGS.

154. EGS presented evidence regarding EOI direct (site-specific) O&M expenses and allocated O&M expenses. The direct O&M costs total over $100 million.

154A. The EOI direct (site-specific) O&M expenses where billed at EOI's costs of providing the service. Because EOI bills at its costs, from the record presented, it can be inferred that the prices charged EGS are not greater than the prices EOI charges other affiliates.

154B. The EOI direct (site-specific) costs can be viewed as a separate "class" of costs similar to the production costs category of expenses.

154C. River Bend's capacity factor improved significantly in 1995 bringing River Bend close to the industry average, and production costs at River Bend are declining

154D. Cities bench-marking report supports the reasonableness of the EOI direct-billed expenses.

155. EGS has met its statutory burden pursuant to PURA § 36.058 as to a total of $79,188,990 (system-wide), which should be included in cost of service as EGS' 70% share of River Bend O&M direct-billed costs. To this amount, $4.8 million is added to correct an error of twice subtracting ESI indirect charges for River Bend operations, the resulting allowance being $83,979,591.

156. The Company failed to provide evidence that would permit it to meet the statutory standard with regard to EOI *allocated* affiliate O&M expenses. There is no evidence of the reasonableness and necessity of these allocations by class of costs, or by individual item. Therefore, all EOI allocated expenses should be disallowed.

Payments to Other Affiliates

157. In accordance with the discussion at §VII.A.6.e.i. of the PFD, test-year payments of $8,207,982 made under Service Schedule MSS-1 are reasonable and should be included in base rates.

158. EGS received services during the test year from Entergy Arkansas, Inc. costing $57,803, from Entergy Louisiana, Inc. costing $17,976, and from Entergy Mississippi, Inc. costing $8,175. They are billed directly, not allocated, to the receiving company. All services are billed at cost; none of the companies receives a profit; the costs are reasonable and necessary and satisfy the affiliate standard prescribed in PURA §36.058(c).

Outside Services

159. EGS included $42,277,529 for outside services in its cost of service, a portion of which was included in its payroll expense. Because of the test-year transition to contract services for billing and metering, these costs should remain as part of payroll expense. (*See* Revised PFD.)

Cost Savings Expenditures

160. EGS requests that it be permitted to recover $55,929,000 of cost savings expenditures (CSE) amortized over five years, or $11,186,000 per year. These costs were incurred from 1994 through the end of the test year primarily attributable to severance and retirement expenses which the Company spent in order to achieve savings related to the merger between Gulf States Utilities, Inc. and Entergy Corporation. The CSE are non-recurring expenses and, as such, should not be included in cost of service.

161. To the extent any merger savings have been realized to date, they have accrued solely to the benefit of shareholders, as they have yet to be reflected in rates.

PURA § 36.062 (PURA95 § 2.208(d)) Expenses

162. EGS demonstrated that it has removed all costs disallowed under PURA §36.062 from cost of service.

Rate Case Expenses

163. The Cities' rate case expenses incurred through November 1997 in the amount of $1,914,340.91 in connection with PUC Docket Nos. 16705, 17899, 18249, and 18290 are reasonable.

164. Pursuant to an agreement among the parties, Cities' rate case expenses will not be surcharged or included in cost of service in this proceeding or any future proceeding.

164A. At the Commission's open meeting on July 10, 1998, representatives of EGS committed orally on the record that the Company will not seek to recover its own rate case expenses in this proceeding or any future proceeding.

Regulatory Commission Expenses

165. The total reasonable regulatory commission expense to be included in cost of service is $5,633,304.

EPRI Dues

166. EGS included $2,283,547 in dues to the Electric Power Research Institute (EPRI) based on the test year. Because the 1997 dues are now known, the 1997 EPRI dues to be included in cost of service as a known and measurable change to test year are total dues of $1,526,621.

Edison Dues

167. The appropriate level of Edison Electric Institute dues included in cost of service is $172,347.

Other Organizational Dues

168. Removing legislative advocacy expenses related to chamber of commerce and other dues, results in a reasonable total of $50,986 for other business and organizational dues.

Payroll Deduction Costs

169. No incremental cost is associated with political action committee contributions that affects EGS' cost of service.

Interest on Customer Deposits

170. The appropriate interest on customer deposits is $1,200,449 based on applying the PUC-approved interest rate of six percent to the test-year-end deposits included in rate base, $8,194,176 for Texas, and five percent to the $14,175,951 Louisiana deposits. (*See* Revised PFD.)

Merger Tracker

171. In Docket No. 11292, EGS and most parties to that docket agreed on a merger stipulation that resolved all issues in the merger case. Included in that stipulation was a "merger tracker" that established a base line against which to gauge the merger-related savings EGS would experience during the years following the merger with Entergy. Under the stipulation, there is to be a 50/50 sharing of savings between shareholders and ratepayers. The tracker also contains a mechanism or methodology for calculating those savings. The appropriate level of shareholder savings to be applied in this rate proceeding is $28,793,500.

172. Paragraph six of the Docket No. 11292 merger stipulation requires that the shareholders' portion be reduced by $2.6 million in years four through eight. The meaning of paragraph six "years four through eight" refers to the rate years established in paragraph nine of the stipulation.

173. If this docket results in a rate reduction, then EGS has guaranteed that rates will be effective beginning in June 1996. In that case, year four (1997) would be six months from that time, and only about four-fifths of the rate period would fall in year four or

after. It is therefore appropriate to discount the $2.6 million by 20% as a credit to the shareholders savings. The investors' share of non-fuel O&M savings should be reduced by $2.08 million under paragraph six.

174. To calculate merger savings, it is necessary to use the calendar year rather than the test year because FERC Form 1 is prepared on an annual basis only and is audited by Independent Auditors. Any other time period would not tie to a FERC Form 1 and would not have the assurance of being audited. Furthermore, FERC Form No. 1 for 1996 reflects the employee reductions used to determine cost savings in this docket and, consequently, ensures that the matching principle is being applied consistently. Accordingly, calendar year 1996 results most closely in the amount of savings contemplated by Appendix 2 to the stipulation.

175. Paragraph four of Appendix 2 of the merger stipulation requires normalization of any significant abnormal item or out-of-period adjustments with an impact greater than $1,000,000. However, not all cost of service disallowances are appropriately incorporated into the savings tracker calculation. Appendix 2 does not require that the tracker be adjusted to match a particular cost of service approved by the Commission in a rate case. It is specifically tied to the FERC Form No. 1, not to the Commission's final order.

176. Based on Findings of Fact Nos. 171 through 175, 50% of merger-related savings as calculated under the merger tracker mechanism, based on calendar year 1996, is $30,873,500, less stipulation paragraph 6 shareholder deduction--$2,600,000 - 20% $2,080,000--leaving $28,793,500 to be added back to cost of service as the shareholders' portion of merger savings.

Non-Reconcilable Fuel and Purchased Power Expenses

177. It is reasonable to include non-reconcilable coal, gas, and purchased power expenses in the amount of $4,853,684 in cost of service.

Decommissioning Expense

178. The cost to decommission the River Bend plant, adjusted for a ten percent ceiling value for contingencies, will be $385.2 million. EGS' 70% share of this amount is $269,640,000.

179. Based on the Commission's previous adoption of low level radioactive waste disposal costs at 7.5%, the fact that River Bend specific inflation factor has been very low in the past several years, and the fact that decommissioning does escalate at a rate higher than general inflation, a 4.81% escalation rate is reasonable.

180. An 11.47% trust equity return and overall 6.6% return for the trust fund results from the most reasonable assessment of return projections.

181. Total company annual decommissioning expense of $8,551,000 is EGS' reasonable and necessary share of River Bend decommissioning costs as evaluated in PFD §VII.B.

Depreciation Rates and Expense

182. The total reasonable depreciation expense for EGS is stated on Commission Schedule I.

Production Plant

183. Because EGS has no specific plan to retire any generating unit soon, it is reasonable to assume that the units will be retired in the middle of the year, because they may, in fact, be retired at any time during the year.

184. The retirement dates for planning purposes should be used for depreciation purposes, as well. The River Bend license expiration date of August 29, 2025 should be used as the retirement date for that plant. For EGS' other generating units, the remaining lives contained in General Counsel Exhibit 34 (González errata) at Attachment CFG-G should be used, except that the remaining lives for Nelson Unit 3, Sabine Unit 3, and Willow Glen Unit 1 should be based on a June 30, 2007 retirement date to be consistent with EGS' plan not to retire these units before 2007. (*See* Revised PFD.)

185. It is reasonable and commensurate with Commission practice to include a negative five percent net salvage value for production plants. A negative five percent terminal net salvage value is a conservative amount that is appropriate given the current uncertainty about future events related to deregulation. Account 310 should be set at zero percent net salvage.

186. The depreciation rate for EGS' nuclear plant should be 2.639%, which was calculated using test-year-end (6/30/96) balances. The non-nuclear production plant depreciation rates should also be calculated using test-year-end balances instead of the 12/31/95 balances used in EGS' depreciation study, because use of the more recent test-year-end balances is preferable for setting prospective rates and accounts for any interim retirements and additions that actually occurred between 12/31/95 and 6/30/96. (*See* Revised PFD.)

Mass Property--T&D and General Plant

187. The reasonable depreciation expense for EGS' Transmission, Distribution, and General plant is reflected in Commission Schedule I.

188. The equal life group (ELG) methodology for calculating depreciation rates is theoretically more accurate than the average life group (ALG) method; however, this is only true where there is enough information available to predict with some degree of certainty how a life (mortality) curve might look in the future.

189. The debate over ELG and ALG is not an either/or dialogue but rather should be viewed as a continuum and must be balanced.

190. In accordance with the discussion at §VII.C.1.b. of the PFD, Staff's proposed depreciation rates, which include application of both the ALG and ELG methodologies, should be used for the mass property accounts.

Amortization Expense

191. EGS' reasonable and necessary amortization expense to provide service is reflected on Commission Schedule I. The amortization expense is calculated using June 1, 1996 as the beginning date and May 31, 1999 as the assumed ending date.

Taxes Other Than Income Taxes

192. EGS' reasonable and necessary payroll taxes are based on the payroll expense approved in this case and are reflected in Commission Schedule III.

193. Texas gross receipts taxes based on the total revenue requirement approved in this case are reflected in Commission Schedule III.

194. EGS' Texas franchise tax was adjusted to reflect a June 1994 Texas franchise tax refund and is calculated based on net taxable earned surplus by applying an effective rate to the revenue requirement approved in this docket. The tax is reasonable and necessary as reflected in Commission Schedule III. (*See* Revised PFD)

195. EGS' reasonable and necessary ad valorem tax adjusted based on disallowance for PHFU is reflected in Commission Schedule III.

Federal Income Taxes

196. It is reasonable to include a consolidated tax savings (CTS) adjustment in cost of service, because Entergy's non-regulated affiliates benefit from their relationship with profitable utilities in the Entergy group, and because it is beneficial to EGS' ratepayers to share in the tax savings realized on a consolidated basis.

197. EGS' share of the CTS is properly based on a hypothetical stand-alone calculation where all affects of disallowed plant are disregarded. EGS' net operating losses (NOLs) would have been fully utilized in 1995 had there been no abeyed River Bend tax deductions.

198. The CTS adjustment is based on a two-year period, 1994 and 1995. As set forth in PFD §VII.E.1., the appropriate amount of CTS adjustment is ($877,030).

199. Because it did not provide the *without* abeyed River Bend calculation, to ensure that all effects of the abeyance and disallowances related to the plant are captured, the Company should amortize the excess deferred federal income tax, related to the $64 million write-off of excess deferred federal income tax, over the remaining life of the depreciable River Bend plant. This is an annual amortization of ($2,166,126).

200. It is appropriate, as an equitable treatment and as a matter of law, to disregard all effects of the abeyed portion of River Bend on an EGS total company basis. Therefore, it is reasonable that EGS' investment tax credits (ITCs) should be amortized in the amount of ($6,707,000). This excludes ITCs generated by the abeyed and disallowed River Bend expenditures and includes both utilized and unutilized ITCs.

201. EGS' request for permanent differences, depreciation adjustment, and temporary differences in its Tax Method 2 calculation is reasonable.

Demand Side Management (DSM)

202. EGS' DSM programs provide little or no benefits to its consumers. The net result of the DSM programs is an increase in revenues through increased energy usage and fuel shifting.

203. EGS applied only the rate impact measure (RIM) which indicated its DSM programs are effective. This test assesses programs only in terms of their effect on rates. Unless the RIM test results are used in comparison with those calculated for the most likely supply-side alternative, the conclusion can be misleading--beneficial programs can be excluded by this test. Applying the utility cost test to EGS' DSM programs shows a net-benefit loss. Thus, the RIM test used in isolation is not reliable.

204. Demand side management resource activities should result in reductions in electric generation capacity needs or reductions in energy usage or both. None of EGS' programs meets this definition. Instead, EGS' DSM programs generally promote the use of electricity.

205. The DSM programs are not in the public interest, are contrary to established Commission policy, and no cost recovery is appropriate or reasonable.

206. EGS' economic development programs are part of the DSM program expenses and are also disallowed. EGS failed to show how its economic development research programs benefit ratepayers.

Request for Good Cause Exception to P.U.C. Subst. R. 23.23(b)(2)(B)(vi)(II) (Wheeling Expenses and Revenues)

207. EGS' wheeling revenues and expenses are not eligible fuel expenses and should be included in base rates in accordance with the principles in Docket No. 17460. Therefore, EGS' wheeling revenues and expenses should be included in the revenue requirement beginning with the effective date of rates in this proceeding.

Treatment of SO_2 Allowance Sales

208. Revenues from sale of SO_2 allowances are to be recorded in FERC Account 254 ordered in EGS' last fuel reconciliation proceeding. Therefore, EGS should remove the $46,950 in SO_2 emission revenues from FERC Account 411.8 - Gains from Disposition of Allowances - and record them in FERC Suspense Account 254.

Rate Design

209. EGS' cost allocation and rate design proposals reflect changes stemming from the merger of Entergy Corporation and Gulf States Utilities Company. EGS used a cost allocation methodology different from GSU's prior cases. The Company also proposed structural changes to its tariffs and has unbundled its rates in preparation for competition. The Company proposes no overall base rate increase.

210. The Company should use weighted billing cycle data for each day of the month to match exactly weather and sales.

211. EGS' weather adjustment for the commercial classes is unreasonable because the Company did not use a uniform method of weather adjustment.

212. An adjustment based on number of customers and weather should be made to demand. Although energy sales and peak demands are not necessarily affected by weather in the same degree, there is also no indication that the difference is substantial. It would be inconsistent to allow EGS to adjust revenues for weather but not demand.

213. EGS' adjustments to the Residential Service (RS), Small General Service (SGS), and General Service (GS) classes based on the number of customers at the end of the test year, the several reclassification adjustments caused by customer transfers between classes, and the miscellaneous adjustments are reasonable.

214. The 12 Coincident Peak (CP) values used by EGS should be replaced with the actual 12 CP, average (54,092 kW).

215. The CP method allocates costs on the basis of system peak. This method assumes that the system-peak drives all production capacity-related costs and assigns costs to customer classes based on each class' relative contribution to the system coincident peak demand.

216. The 12CP method is based on the twelve monthly peaks of EGS' various jurisdictions, thus reflecting, to a degree, the kWh load patterns of EGS' jurisdictions.

217. The use of the 12 CP method reasonably allocates production capacity-related and transmission capacity-related costs at the jurisdictional level.

217A. Special-rate revenue (for LQF, SMQ, MSS, and EAPS) should be directly assigned to the jurisdiction of origin. This will preclude a $396,000 subsidy from Texas to Louisiana.

218. Wheeling expenses should be accorded base rate treatment. Wheeling revenues should be treated as base rate revenues.

219. The wheeling classes should be included as separate classes in the cost of service studies. The service transmission tariff should be treated separately from the access service transmission tariff.

220. Deleted.

221. The continued use of the A&E 4CP allocator is the most reasonable methodology for allocating production and transmission plant among classes. The A&E 4CP allocator sufficiently recognizes customer demand and energy requirements and assigns cost responsibility to peak and off-peak users. It best recognizes the contribution of both peak demand and the pattern of capacity use throughout the year.

222. The A&E 4CP method is also preferable because it is devoid of any double counting problem.

223. The Company's methodology for allocating distribution plant is the most reasonable because distribution substation and primary line costs are localized in nature; that is, they are designed and constructed to handle loads close to the point of ultimate use. The Company used the simultaneous peak load of each customer class Maximum Diversified Demand (MDD) as the basis for allocating those costs.

224. Current cost of services studies are not based on geographical differences. Classes are not divided based on geography, and industrial sites are not self-sufficient islands. The use of city streets and property enables EGS to have an integrated utility system from which all ratepayers benefit.

225. EGS' allocation of local gross receipt and franchise taxes to the classes based on total rate schedule revenues is reasonable.

226. The decommissioning expense does not vary with the amount of energy the plant consumes or produces. The costs are fixed and do not vary with the level of generation.

227. The allocation of decommissioning expense to both the Texas jurisdictional and class levels on the basis of production capacity-related costs is reasonable.

228. The Company allocates Cash Working Capital and other non-investor-supplied capital that serves as a general source of funds by a composite factor that recognizes that CWC is fungible, which is reasonable.

228A EOI expense should be allocated consistent with the Commission-approved rate design allocation in this docket.

229. Synchronizing fuel revenues and expenses in the compliance cost of service study by using the rate-year fuel expense and fuel revenues will ensure compliance with P.U.C. SUBST. R. 23.23(b)(2)(D)(i)(I), and will ensure the proper calculation of any allocation factor based on measures of cost including fuel and purchased power expenses.

230. The FERC staff method used by the Company to classify production non-fuel O&M expense is a reasonable method and produces reasonable results.

231. Just as it may seem unfair to have the industrial customers absorb the bad debts of a few individuals, it is just as unfair to have the great majority of dutiful residential ratepayers pay those debts. The passing on of such costs to others is generally factored into the cost of doing business. It is a cost that is better absorbed by the many. Therefore, uncollectible expense should be allocated at both the jurisdictional and class levels on the basis of jurisdictional and class operating revenues.