In response, Mr. J. David Wright, EGS's Manager of Regulatory Accounting, testified that the balance in the unbilled ADIT is the result of a cumulative temporary book and tax difference and is ongoing normalization accounting and not a one-time accounting change. EGS Ex. 148 at 44.

The ALJs conclude that EGS should not recover these taxes from ratepayers. EGS's own 1993 financial statement[481] describes the income effect due to the change in accounting principle as a net increase to 1993 income of $10.7 million. In Louisiana, the unbilled revenues related to this one-time accounting change were shared equally between the ratepayers and shareholders. Therefore, the LPSC also split the tax between ratepayers and shareholders.[482] In Texas, there has been no credit to rate base or cost of service in 1993 that would benefit ratepayers from this increased income. The ALJs agree with Cities that it would be inequitable to permit a shareholder windfall without requiring the shareholder to be responsible for related tax effects. Accordingly, we recommend removing $15,385,495 from rate base.

2. ADIT Related to Net Operating Losses

EGS included $44,089,867 in net operating losses (NOLs) in rate base.[483] The ALJs conclude that this amount should be removed from rate base, as recommended by Staff witness Ms. Romines.

Net operating losses occur when total deductions reflected on a corporation's tax return for any year exceed gross taxable revenue. They may be carried back to offset net taxable income for the prior three years. If some or all of the NOL remains unused after the carry back, that amount may be carried forward for 15 years. When an NOL is carried forward, some portion of the

[481]Cities Ex. 108 at Bates 542.

[482]Cities Brief, Appendix at LPSC Order No. U-19904-C at 16 and 20.

[483]Schedule G-7.4, page 3 (Acct. No. 382615).

deductions claimed on the tax return will have failed to produce a tax benefit, for example, to offset taxable income. Thus, the tax-reducing benefits of those deductions are deferred until such time as the NOL carry forward can be used. EGS Ex. 146 at 14-15.

EGS's total deductions on its actual tax returns were not affected by the abeyance of River Bend costs, but the *revenue stream* was affected. Because the abeyed River Bend (ARB) plant has not been included in EGS's rates, the revenue stream produced by the ARB is zero. EGS claimed approximately $858,803,000 in *tax depreciation* on its tax returns for the ARB. Tr. 9178. It also claimed that ARB *interest* totaled approximately $418,341,000; of that amount approximately $342 million has been excluded from the calculation of federal income tax (FIT) in prior rate cases.[484] The result is that the two ARB deductions, depreciation and interest, are about $1,142,000,000 greater than the revenue stream, and the combination on the actual tax return produces an NOL. When taxes are calculated *with* ARB, NOLs are generated. But when ARB is not considered in the tax calculation (*without* ARB), the actual NOL balance at test-year end is eliminated. GC Reply Brief at 5.

Staff witness Ms. Candice Romines asked the Company to do an ARB *with and without* calculation. In rebuttal, Mr. Wright restated FIT but only on a Texas retail basis, not capturing the revenues lost due to the Louisiana Commission's deregulation of a similar $1.4 billion of River Bend plant. EGS Ex. 148 at Ex. JDW-11. Because the Company did not calculate the NOLs related to the ARB on a total company basis, the amount of NOLs used up in the "hypothetical" tax calculation, required for regulatory treatment of disallowed plant, is not known. It is known that the Company

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[484] *See* Tr. 9202-9203, 9302-9303, 9333. For two years following Docket No. 7195, FIT was calculated on an actual tax basis and ratepayers benefitted from the interest deduction.

failed to account for approximately $490 million in tax depreciation related to the ARB.[485] Mr. Wright also testified that if Staff's methodology is applied on a Texas retail basis, the NOL balance at 1995 year end would be zero. EGS Ex. 148 at 27.

The Internal Revenue Service (IRS) requires all effects of disallowed plant, including total company depreciation and interest related to it, to be removed from the FIT calculation. The IRS concluded that reflecting depreciation related to disallowed costs in the FIT expense for ratemaking would violate normalization rules.[486] The ALJs conclude, faced with no evidence to the contrary, that all NOLs would have been utilized if applied using the total company or Texas retail effects of the ARB deductions and reduced revenues.

Mr. Wright testified that if the Commission follows Ms. Romines advice, then a portion of the return to accrual adjustment would result in a double dip by eliminating $1,926,024 twice. The ALJs recommend that an adjustment be made to ensure that the $1.9 million return for NOL is not removed twice. EGS Ex. 148 at 43.

3. ADIT Related to Alternative Minimum Tax

EGS has also increased rate base by $38,965,455 in ADIT related to alternative minimum taxes (AMT). Staff and Cities excluded these deferred taxes from rate base. Mr. Arndt testified that the ADIT associated with AMT relates to tax losses due to disallowances associated with River Bend and actions in other jurisdictions. Also, the AMT credit carry-forwards relate to prior periods and

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[485]Tr. 9188; EGS Ex. 148, JDW-11 at 5.

[486]*See* EGS Ex. 146 at Ex. JIW-3, IRS private letter ruling per *Inquiry into the Reasonableness of the Rates and Services of Gulf States Utilities Company*, Docket No. 12852, ___ P.U.C. BULL. ___ (May 26, 1995) (not published) [hereinafter Docket No. 12852]. *See also PUC v. Texas Utilities Electric Company*, 935 S.W.2d 109, 110 (Tex. 1996); citing 901 S.W.2d at 411, the Texas Supreme Court concluded that the Commission has neither the power nor the discretion to consider disallowed expenses or capital costs to determine the utility's income tax expense for ratemaking purposes.

are used to offset EGS's federal income tax liability. Cities Ex. 106 at 84-85. Cities noted that in Docket No. 12852, Gulf States Utilities' actual interest deduction on its FIT return was not recognized for rate-setting purposes even though the Company actually took the expense deduction associated with excluded plant on its tax return. Also, in that case, depreciation on the portion of River Bend excluded from rate base was not included in the FIT calculation for rate-making purposes.[487] And, the Louisiana Commission excluded ADIT associated with AMTs in EGS's last two rate cases because they were generated from plant excluded from rate base.[488]

EGS attempted to prove that AMTs increase as a result of disregarding the effect of the abeyed portion of the River Bend plant.[489] As discussed above and at §VII.E.2. below, EGS declined to perform a calculation that removed *all* effects of the excluded River Bend plant.[490] Cities contend that this "strategic choice by EGS" allows it to claim other parties cannot prove the AMT (or NOL) arose due to excluded plant. Cities Brief at 95-96. General Counsel Ex. 71, appended to General Counsel's reply brief, illustrates that when the tax depreciation and interest related to the disallowed plant are removed, the AMT *credit* appears. That evidence demonstrates that AMTs did not grow as EGS insinuates and as EGS witness Mr. Wright testified. EGS Ex. 148B, Tr. 9209-9213.

EGS would argue that no credit appears because it is not appropriate to relate AMT to the ARB plant. GC Ex. 44 at 23. Cities and Staff conclude that to eliminate the effects of the abeyed

[487] Docket No. 12852, Order on Rehearing at Finding of Fact Nos. 91A and 92. The ALJs rely on parties' representations regarding what happened in Docket No. 12852. The PFD is abbreviated--it does not discuss the tax evidence at all--and the findings of fact are also not enlightening on this issue.

[488] Cities Brief at 95; *See*, Cities' Appendix A to Brief: LPSC Order No. U-19904-C at pages 21-22 (Dec. 29, 1994).

[489] EGS Ex. 148 at 27-28; Ex. JDW-11.

[490] GC Ex. 44 at 13-15; GC Ex. 44B.

plant for tax purposes, as required by the IRS,[491] all operating loss deductions must be captured, including AMT related to the Louisiana deregulated plant. EGS ignored the fact that its tax calculation includes revenues and depreciation and other adjustments based on the total EGS company, which includes the Louisiana decision to exclude plant.[492] EGS also ignored interest related to the abeyed portion because Mr. Wright testified the interest was not reflected on the Company's books as being related to River Bend. Tr. 9194-9195.

The ALJs conclude that the evidence is not absolutely clear that AMTs will not increase as a result of disallowed River Bend adjustments, but find Staff's exhibit (GC Ex. 71) and testimony at hearing related to it persuasive. Further, because Mr. Wright did not include all the affects of the ARB in his JDW-11 calculation, his testimony does not address the total company affect on AMT; therefore, we recommend the AMTs be removed from rate base for the reasons discussed herein.

4. Miscellaneous Adjustments

The ADIT associated with EGS's cost savings expenditures discussed at §VII.A.8. should be removed consistent with the decision at that section of the PFD.

Mr. Wright testified that River Bend Unit 2 cancellation costs are not included in rate base. Therefore the ADIT associated with this canceled plant should not be in rate base. EGS Ex. 148 at 43.

ADIT 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. GC Ex. 44 at 24.

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[491]*See* EGS Ex. 146, Ex. JIW-3, private letter ruling.

[492]EGS Ex. 148 at JDW-11; Tr. 9175-9176.

E. Plant Held for Future Use

EGS proposes to include in rate base $56,604,500 of plant as PHFU, part of which includes the Neches Station and Louisiana Station No. 2 currently held in extended reserve shutdown.[493] General Counsel, OPC, and Cities oppose this request. The ALJs recommend that the request regarding these plants be denied as discussed below. In addition, the property tax expenses related to the units should be excluded from the cost of service.

In order to bring assets out of reserve shutdown and into rate base as PHFU, a utility must demonstrate that the PHFU will be fully used and useful to ratepayers within a ten-year period and that the utility has a definite, specific, and reasonable plan to use the facilities.[494]

The Commission addressed this issue in its Preliminary Order, asking:
Is the Company's plan for Plant Held for Future Use (PHFU) reasonable? Should the Commission require the Company to engage in competitive bidding to determine

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[493]Schedule B-1, line 3; Schedule D-3 at page 1 showing $56,669,000. The amount requested for FERC Account 105 is $56,604,500. *See* EGS Ex. 106, Turner Direct, at 20a, n. 2, which explains that the proposed Blue Hills Nuclear Station is excluded.

[494]Docket Nos. 7195, 14 P.U.C. BULL. at 2151. The Commission found that Gulf States did not have a *definite* plan to place certain plants in service within 10 years; therefore, it excluded those PHFU plants from rate base. *See* Findings of Fact Nos. 215, 216, and 217, 14 P.U.C. BULL. at 2414.

See also Application of HL&P for Authority to Change Rates, Docket Nos. 8425 and 8431, 16 P.U.C. BULL 2199, 2565-2566 (June 20, 1990) [hereinafter Docket Nos. 8425 and 8431]. *Application of Texas-New Mexico Power Company for Authority to Change Rates*, Docket No. 8928, Findings of Fact Nos. 54 & 55, 15 P.U.C. BULL. 2026, 2155 (Feb. 24, 1990) [hereinafter Docket No. 8928], future use of transmission line was indefinite; *Application of Brazos Electric Power Cooperative, Inc. for Authority to Change (Reduce) Rates,* Docket No. 8868, Findings of Fact Nos. 16, 30, & 38, 16 P.U.C. BULL. 1037, 1112, 1123-1125, (Dec. 14, 1989) [hereinafter Docket No. 8868] inclusion of PHFU in rate base is permitted where the applicant demonstrates specific plans ensuring that the particular investment will be fully used and useful in providing electric service to the public within a ten-year period from test year-end.

if third parties can provide resources more reasonably than the Company can from PHFU? (e.g., Neches Station Units 4,5,6 and 8; Louisiana Station No. 2 units 7,8,9).[495]

1. EGS's Plan

EGS included Neches Station Units 4, 5, 6, and 8 and Louisiana Station No. 2, Units 7, 8, and 9 in its rate base request. These plants were removed from service and placed in extended reserve shutdown in August 1985. In 1996 EGS filed its Load and Capability Forecast with the PUC. That forecast indicated that Entergy system's reserve margin would fall below 15 percent in 2004. EGS witness Mr. Kenneth Turner, Director, Resource Planning, testified this means that all of the system's capacity currently in extended reserve shutdown will have to be returned to service. EGS Ex. 106 at 25; Ex. KMT-6.

In response to the Commission's Preliminary Order question, Mr. Turner testified that Entergy ranks its plants by cost, and each plant competes with the others in the determination of which is the least-cost option. After this ranking, the least-cost option, which includes short-term purchases, is selected. In the past few years, short-term purchases have been the least-cost method for meeting projected load requirements. Mr. Turner believes EGS is in a strong negotiating mode because power sellers know Entergy has a competitive alternative in these plants. He also testified that the timing of the need for the PHFU facilities depends on market conditions and the availability of short-term purchases at prices that are competitive with, or less expensive than, returning the plants to service. He concluded that the plan to deploy the facilities is reasonable because the formal commitment to use them will not occur unless they prove to be the least expensive alternative. *Id.*

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[495] Preliminary Order at 26 (Jan. 22, 1997).

at 4. Finally, he said Entergy does not need to engage in competitive bidding because it is already accomplishing the same results by using short-term purchases. EGS Ex. 107, Turner Supp. Direct, at 3-5.

2. OPC's Position

Mr. Turner claimed that EGS will receive reduced MSS-1 payments by returning these plants to service because EGS's capability will increase by the capacity of these units. EGS Ex. 106 at 22. Mr. Allen, testifying for OPC, noted that EGS provided no calculation to support this claim, nor did it quantify any savings to ratepayers. In response to a data request from OPC, EGS stated, if Neches Units 4, 5, 6 and 8 are taken out of storage, they would be used to provide peaking service, generally operating at less than a 10 percent annual capacity factor. Mr. Allen testified that if any level of these plants is allowed in rate base, it should not proportionately exceed the forecasted capacity factor for each unit. OPC reduced rate base by $7,861,941 to eliminate consideration of the unused plants. OPC Ex. 48 at 25 and Document #12.

3. Cities' Position

Daniel Lawton, Cities' expert, recommended denying all of the request except a portion related to two transmission lines that were misclassified amounting to $2,647. These lines were in service prior to the end of the test year; however, the Company inadvertently did not remove them from PHFU.

Mr. Lawton also raised the following cogent issues:

a. When the plants become used and useful under EGS's plan, the Company proposes to be deregulated. Thus, EGS asks Texas ratepayers to pay currently for plant they may never get to use; EGS may sell or transfer the plant to another subsidiary or third party.

b. EGS's customers would also pay now reserve equalization payments under MSS-1 for system capacity it does not need now.

c. In Docket No. 14965, the Commission ruled that because CPL had not filed an integrated resource plan (IRP), the PHFU had not been selected as CPL's best resource option. The Commission disallowed the request and also found that CPL's potential non-utility competitors do not earn a return on their idle plants while waiting for an opportunity to compete.[496] EGS has not yet filed an IRP plan. Cities Ex. 102 at 45-46.

4. General Counsel's Position

Mr. Van Sickle testified that EGS has not demonstrated in its last three rate cases a *definite* plan for placing Neches Station Units 4, 5, 6, and 8 in use within 10 years. He also noted that at a technical conference on May 9, 1997, EGS indicated that the units would only be operated on a seasonal basis to cover the summer and winter peaks and would remain idle during off-peak seasons. Also, EGS could not give a definite in-service date or indicate how long it expected to operate the units once they were brought back into commercial operation. GC Ex. 46 at 41.

Mr. Van Sickle demonstrated that EGS's proposal to bring these plants on line is not the most economical option it will have by the year 2005. EGS stated its decision to bring the units back into operation is an economic decision; Mr. Van Sickle believes because doing so is not the most *economical* option, EGS's plan regarding the plants is tentative and indefinite. *Id.* at 42-43 (Confidential).

EGS requested two parcels of land or land rights associated with transmission facilities to be included in rate base as PHFU. Part of the transmission line is currently being used by the system

[496] Docket No. 14965, Finding of Fact No. 35, Order on Rehearing at 26.

under certificate of convenience and necessity (CCN) Number 10035 approved in April 1993. Five acres adjacent to the Orange substation site are planned to be used as part of a substation expansion in the year 2004. Mr. Van Sickle finds these to be part of a *definite* plan under the PHFU standard and recommends that $26,212 be allowed into rate base as part of this plan. *Id.* at 43-44.

5. EGS's Response

In rebuttal, EGS argued that returning the units to service *could* be less costly than other alternatives, and returning the units to service is the least costly option that is *completely within EGS's control*. Mr. Turner also testified that PHFU participation as an alternative must be fluid and not established in time. Thus, EGS's plans provide flexibility to use the most economic resources available and adapt to future wholesale power market changes. EGS Ex. 139 at 51.

EGS argues that to the extent these resources are not the most economical, they would be sold to the Entergy pool for sales to other Operating Companies or for sales off-system. Either way, EGS ratepayers would be fairly compensated by the System. EGS Reply Brief at 10.

Mr. Turner, responding to OPC, testified that Mr. Allen's proposal to proportionally allow the capacity used in rate base does not work, because the capacity factor is dynamic, varying over time according to the participation of the unit, which in turn is determined by factors such as technology, unit life cycle, and system requirements. EGS Ex. 189 at 50.

6. ALJs' Recommendation

The request for PHFU should be denied for the following reasons:

a. Relation to Entergy System

EGS is part of the Entergy System, which is planned and operated as a single integrated electric system that is intended to benefit all customers system-wide. Bringing these plants on line as a power source may benefit Entergy ratepayers other than EGS customers, even though EGS ratepayers would be paying the return on the assets. The Commission has not had an opportunity to review such a circumstance to determine whether this plan would meet its IRP goals or its PHFU policy.

EGS argues that even if EGS ratepayers do not benefit from the use of these plants, they will be used to provide service in the Entergy service area; similar units are in the rate bases of other Entergy Operating Companies, where they currently provide benefits to EGS's Texas ratepayers as resource options.[497] However, EGS does not benefit under Schedule MSS-1 until the unit is brought into service. EGS Ex. 106 at 22. It is not clear from that testimony whether "brought into service" means the time when the plant is in rate base as PHFU or the time, such as in the year 2004, when the plant actually begins providing power.

b. IRP Process

i. Ten Percent Plant Use

The plan to use only ten percent of the plant during peak times may not meet the used and useful standard. The question remains, is such minimal use a reasonable alternative to another power source and is it economically justified? This is an issue ripe for an IRP proceeding.

[497]EGS Reply Brief at 9 citing Tr. 6411-6412.

ii. Solicitation

The Company's argument that it is not necessary to do a solicitation because the cost of returning plant to rate base is already ranked among the Entergy system alternatives does not go far enough. There is no proof in this docket that the costs surrounding return of these plants to rate base meets a solicitation-type protocol under PURA §34.051, which requires that a resource solicitation be conducted as required by 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.

iii. Return on PHFU

In ascertaining the least-cost options under an IRP, the Commission should take into account the carrying costs or return associated with PHFU in rate base. Also, requiring competitive bidding will ensure that EGS does not place these units into operation under pressure to justify their inclusion in rate base. GC Reply Brief at 11. The ALJs find that EGS's load forecast on which it relies here and the portions placed in evidence in this case do not address these issues.

Based on the foregoing considerations, and in conformance with the decision in Docket No. 14965, we find it is necessary for EGS to engage in the IRP process before the Commission should adopt its plan to include these plants in rate base as PHFU.

c. <u>Competition</u>

The trend to sell off plants such as these in the transition to competition makes EGS's "plan" tentative, and even less likely that the plants will be used and useful to EGS ratepayers. EGS argues that the PHFU standard does not include such considerations.[498] Nevertheless, the transition to competition and deregulation drives much of the direction this Company will take and many of the decisions in this case. It is a period of time unlike any before where PHFU was considered, except Docket No. 14965, and unless the Company can say that it definitely will not sell off the plants, then such an option makes its PHFU plan indefinite. The evidence on this issue suggests that selling or transferring the plants may not benefit current ratepayers, and surely will not make them useful to ratepayers, a factor clearly violating the PHFU requirement that the plant become used and useful. To quote Judge Newchurch, in such a case, ratepayers would "pay for nothing."[499]

The ALJs conclude that EGS has not met its obligation to prove that it has a definite plan to return these plants to used and useful status within ten years in order to justify requiring ratepayers to begin paying for them in rate base. In addition, we agree with EGS that Mr. Van Sickle's proposal to include the transmission line and substation land in rate base at this time fails for the same reasons as discussed herein. The load forecast for the area is no more certain than the load forecast for the extended reserve shutdown units.

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[498]EGS Reply Brief at 8; Tr. (Lawton) 6799.

[499]Docket No. 14965, Proposal for Decision at 43.

F. Cash Working Capital

A wide disparity abides among the parties regarding this issue. EGS initially sought a reduction of $8,053,000 from cash working capital.[500] In rebuttal, the Company agreed with certain adjustments proposed by Cities and Staff and reduced that another $1.5 million to a negative $9,559,654.[501] The General Counsel reduced the Company's request by $105,031,000 and Cities reduced it by $47,588,411. The ALJs recommend adding a negative $24,519,068 to the Company's request resulting in a reduction of $34,078,722 from EGS cash working capital.[502]

EGS performed a lead-lag study in 1994 as required by P.U.C. SUBST. R. 23.21(d)(2)(B)(iii)(V). The lead-lag study determines the amount of investment that is necessary to fund the Company's normal day-to-day business activities before the Company is reimbursed by its customers. It measures the length of time from rendering electric service until payment is received from the customer (lags) and the length of time from receipt of goods or services from the Company's vendors until the vendors are paid (leads). The net leads/lags from the study are applied to various categories of expense items in the cost of service. EGS Ex. 118 at 28-29.

The substantive rule states in relevant part:

> (-a-) The lead-lag study will use the cash method; all non-cash items, including but not limited to depreciation, amortization, deferred taxes, prepaid items, and return . . . will not be considered.

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[500]Schedule B-1 line 4; Schedule E-4 contains the calculation of the cash working capital allowance for O&M expenses obtained from the lead-lag study. EGS Ex. 118, Wright Direct, at 28.

[501]EGS Ex. 148 at 96-97, Ex. JDW-15 at 1.

[502]Because the ALJs are not absolutely certain of the dollar amounts taken from Cities' adjustments which we adopted, this number may not be accurate. Parties, in particular Cities, should review our decisions and make any necessary corrections to the dollars in their exceptions to the PFD. Schedule IV reflects an adjustment of $25,430,000 for a ($33,483,000) test year cash working capital.

> (-b-) Any reasonable sampling method that is shown to be unbiased may be used in performing the lead-lag study.
>
> (-c-) The check clear date, or the invoice due date, whichever is later, will be used in calculating the lead-lag days used in the study. In those cases where multiple due dates and payment terms are offered by vendors, the invoice due date is the date corresponding to the terms accepted by the utility.[503]

Both Cities' expert Jacob Pous and Staff witness Debbie Witbeck concluded that the Company's lead-lag study is so flawed as to be unreliable.[504] Under the rule, if

> the utilities' lead/lag study is determined to be so flawed as to be unreliable, in the absence of persuasive evidence that suggests a different amount of cash working capital, an amount of cash working capital equal to negative one-eighth of operations and maintenance expense including fuel and purchased power will be presumed to be the reasonable level of cash working capital.[505]

Even though Cities provided evidence of various adjustments to the study, in their post-hearing briefs Cities joined the General Counsel in urging that Staff's negative one-eighth of O&M calculation, as required by the rule, be adopted. Cities Brief at 6.

1. General Counsel's Position

The rate filing package and P.U.C. SUBST. R. 23.21(d)(2)(B)(iii) require such information to be filed at the time the Company files its rate case. The RFP instructions to Section E-4 require that workpapers supporting the Company's request "shall include *all* documents used in the development of the study or necessary to replicate the study."[506] Ms. Witbeck recited in testimony the difficulty Staff had in reviewing EGS's cash working capital material mainly due to a lack of

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[503]P.U.C. SUBST. R. 23.21(d)(2)(B)(iii)(V)(a), (b), & (c).

[504]Cities Ex. 104 at 89, GC Ex. 36 at 9.

[505]P.U.C. SUBST. R. 23.21(d)(2)(B)(iii)(VI).

[506]Official Notice No. 1 at E-6, Emphasis theirs.

supporting documentation. Also, Ms. Witbeck contended that EGS's sampling was flawed, and the check float could not be verified because the Company never supplied copies of canceled checks. Staff found the lead-lag study is so flawed as to be unreliable. GC Ex. 36 at 10; Attachment DW-2.

First, Mr. Wright testified in rebuttal that the Company provided the same type of lead-lag study it had filed in Docket No. 12852. He did not reveal that the Staff did not review that study and did not provide testimony about it due to resource constraints (Tr. 9258) or that the study was given only cursory review during that rate case.[507] Cities Brief at 9. Instead, Mr. Wright testified here that in Docket No. 12852, "all parties had full opportunity to review the lead-lag study and relied on the study to propose certain adjustments which the Commission ultimately adopted." EGS Ex. 148 at 69. Furthermore, Mr. Wright criticized Ms. Witbeck because she did not attempt to compare EGS's lead expense and float days to other Texas utilities to determine the reasonableness of the EGS lead-lag analysis. *Id.* at 70-71. The ALJs find this to be a curious statement, considering the fact that EGS failed to make similar comparisons in order to support its affiliate expenses, and especially because the General Counsel and Staff do not have the burden of proof to prove the reasonableness of any part of EGS's case.

Mr. Wright testified that the cash working capital analysis he presented can be reasonably replicated using the data provided in workpapers and the RFI responses. Mr. Wright testified that he or his staff provided RFI responses they thought answered the questions asked, and no one from the Commission called to ask for additional information or clarification. For example, he was not contacted by Ms. Witbeck to tell him that the canceled checks were not legible. Mr. Wright also stated that EGS in fact did supply copies of canceled checks in response to Staff's RFI; the response

[507]Docket No. 12852, PFD at 2; 22.

was voluminous; at the General Counsel's request the Company delivered the checks to the Commission, but Mr. Wright believes that for some reason Ms. Witbeck did not receive them. EGS Ex. 148 at 58-65.

Without describing each area of complaint contained in Staff's Attachment DW-2, and while the ALJs understand the problem and the fact that the material was voluminous, the evidence suggests that EGS did provide the material in response to RFIs. Because the evidence is not totally clear regarding exactly what transpired during the discovery phase, and because EGS apparently filed the same kind of lead-lag study the Commission found acceptable in Docket No. 12852, we are reluctant to apply the one-eighth rule, as we perceive doing so would be unreasonably punitive. Nevertheless, we also find that EGS did not comply with the requirement that it provide sufficient information in its rate filing package so that its cash working capital analysis could be replicated. It may have provided the necessary information in discovery, but that is not what the instructions contemplate.

Even though the ALJs do not recommend adopting the one-eighth rule, we do recommend the Commission order EGS to properly file its cash working capital information in its 1998 rate case so that the lead-lag study can be replicated by Staff without the necessity of requesting information through the discovery process. Even if the Commission does not include such a provision in its final order in this case, the Company knows the RFP requirements and should know that what it provided in this docket was insufficient. EGS will not be able to point to the 1994 lead-lag study as a model to be followed for the next rate case.

2. Cities' Position

Mr. Pous described various errors he detected in the Company's lead-lag study and proposed several adjustments to the lead-lag analysis as an alternative to the one-eighth rule. The ALJs have examined that proposal and EGS's response to reach a decision on this matter. EGS changed very modestly only a handful of items identified by Mr. Pous.[508] The following items represent Cities' specific dollar adjustments to cash working capital.

a. Revenue Lag Related to Meter Reading and Billing/Payment

Cities recommend the revenue days of 3.61 days for meter reading proposed by EGS be reduced to 1.46 days. Before the merger with Entergy, and as reported in Docket No. 12852, EGS was able to perform the meter-reading-to-billing function in 1.46 days.[509] That occurred during the period ending 30 September 1993, the year prior to the current analysis. Mr. Pous concluded that it is not appropriate to charge customers for inefficiencies (1) that may be attributed to the merger between Gulf States Utilities and Entergy or (2) that are temporary in nature due to the transition in the early stages of the merger.

Mr. Wright testified that his calculation of meter reading to billing days is based on taking the average dates and does not result from staffing reductions or transitional problems. Apparently, the lag for Large Power customers decreased since the last rate case from 8.55 days to 5.53 days, and Mr. Pous recommends no adjustment for that class. EGS contends Mr. Pous is therefore inconsistent.

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[508]Mr. Pous criticized the Company's inclusion of prepaid items and its sampling method but did not recommend a specific adjustment for these alleged errors. The ALJs find that the sampling Mr. Pous referred to, certain wire transfers, may have caused unrealistic or skewed results, although the sampling process of random selection appears appropriate. It may be necessary for the Company to exercise judgment in such cases and repeat the random selection process to get a more realistic result. *See* Cities Ex. 104 at 90; EGS Ex. 148 at 73-74.

[509]Cities Ex. 104 at 95; Ex. JP-16. Cities cite the Company's workpaper E-4, page 26 of 47 from its Docket No. 12852 rate filing package.

The ALJs find that the evidence does not require an adjustment to these EGS's proposed lag days. Mr. Pous' only speculated that the difference in CIS meter reading since Docket No. 12852 is attributable to the merger.

Cities contend the proposed 21.63-day billing-to-payment revenue lag is excessive. Cities Ex. 104 at 97. The Docket No. 12852 lag period was 19.6 days. Cities propose to reduce the billing-to-payment lag from 21.63 and 20.50 to 18.66 days. EGS contends this understates the period of time necessary for it to fully collect its revenue from customers. EGS Ex. 148 at 79.

In this case, EGS used a snapshot approach and tested receipts from one day of each month during 1994. Mr. Pous calculated a dollar weighted average revenue lag which assumed that customers take 14 days to pay their bills, rather than the 16 days allotted them under P.U.C. SUBST. R. 23.45(b), because not every customer pays on the last due date. *Id.* at 97, Ex. JP-17.

The ALJs accept that the 21.63 days reflects a mix of those customers who pay early and those who pay later during the disconnect period, as explained by Mr. Wright, but we question whether the disconnects really tip the balance to 16. Nevertheless, the ALJs find no reason to justify changing the Commission-required 16-day pay schedule.

b. <u>Vacation Pay</u>

Cities allege EGS failed to recognize or segregate vacation-related payroll which is approximately \$6 million annually while recognizing separately other categories of as low as \$60,000. EGS assumed 14.81 lag days for regular payroll. Mr. Pous testified there is a longer deferred payroll period associated with vacation pay and recommended 26.51 days. This difference was recognized in Docket No. 13369.[510] EGS incurred $5,960,153 in vacation charges for all operations during the test year. The average vacation time for EGS employees is 3.43 weeks. The dollar-weighted lag days associated with vacation pay is 210.67.[511] Recognizing vacation time as a separate component of payroll results in a $3,198,219 adjustment to requested cash working capital.

Mr. Wright testified that the Company does not accrue vacation pay on the books in years prior to when vacation pay is paid. Because EGS does not record expense in this manner the 210.67 day vacation pay lag is not an appropriate cash working capital item in this case. EGS Ex. 148 at 85.

The ALJs disagree. The substantive rule does not specifically address expenses that do not come with invoices; however, they appear to be similar to the federal income tax expense calculation which the rule requires be measured at the interval between the mid-point of the annual service period and the actual payment date of the utility. P.U.C. SUBST. R. 23.21(d)(2)(B)(V)(f). Because employees' earn vacation time before vacation is taken and vacation pay is paid by the Company, we find it reasonable to use Mr. Pous' calculation of an additional $3,198,219 reduction in cash working capital as a reasonable estimate of the lag between when the employee earns the vacation time and when the Company pays him or her for it.

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[510]*Application of West Texas Utilities Company for Authority to Change Rates*, Docket No. 13369, _____P.U.C. BULL._____ (Nov. 9, 1995)(not published) [hereinafter Docket No. 13369]. This was a settled case and is not appropriate as precedent. However, in rebuttal testimony, apparently adopted in the final order, WTU accepted the separate lead associated with accrual of vacation pay because vacation pay service and payment patterns differ from regular payroll. Cities Ex. 104, Schedule JP-18 at p. 3.

[511]Cities Ex. 104 at 99-100, Schedule JP-19.

c. **Other O&M expense**

Cities noted several problems concerning Other O&M expense:

(1) EGS proposed a 7.61-day lag period for its "$100,000 and over" stratified range. In 1993, EGS developed a 65.12-day lag period for this range. Mr. Pous testified that the Company used 40 percent more invoices in the sample in Docket No. 12852 than it did in the 1994 study.

(2) Prepaids represent seven percent of the sample in the last case and 17 percent in this case.

(3) EGS used the accounting transactions rather than the period from when the Company received a product or service until it paid for such product or service.[512]

(4) EGS failed to recognize the one-year service period for Thrift Plan users.

(1) Mr. Pous found that EGS included certain insurance invoices in two locations: prepayment component of rate base and invoices attributable to nuclear property insurance in the negative lag days for Other O&M. The amount in controversy is relatively small, $785,326 total company. EGS denies there is a double counting and says that it paid these amounts through installment payments but never included them in rate base as prepaid account balances. The ALJs are not persuaded that a double counting exists.

(2) EGS agrees it erred in including the NISCO payments in cash working capital. The lag days increase from 7.61 to 12.29 days. Cities Ex. 104 at 105. The weighted-dollar lag increases from

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[512]Cities Ex. 104 at 104, Schedule JP-23. Mr. Pous noted that in Docket No. 11735, the Commission ruled that the accounting transaction date is not the date that should be used for cash working capital purposes. It should be the date goods are received by the utility. *See Application of Texas Utilities Electric Company for Authority to Change Rates,* Docket No. 11735, Finding of Fact No. 72, 20 P.U.C. BULL. 1029, 1447, Commission Schedule VI at 1560 (May 27, 1994) [hereinafter Docket No. 11735].

27.67 to 28.84 for this correction and amounts to approximately $643,000. EGS Ex. 148 at 88. The ALJs accept EGS's correction.

(3) Cities contend that EGS's Other O&M expense ignores the requirement of subsection (c) of the lead-lag rule to use the later of the check clear date or the invoice due date. Cities Ex. 104 at 91. EGS explained that its check float period (seven days) permits it to comply with the substantive rule. However, in response to Cities' complaint, EGS conceded that the stamped dates on the back of its checks could be misleading and revised the dates in the float calculation to correspond to those shown on the bank statements and the latest date on the canceled checks. This raised the check float from 6.75 days to 7.03 days. *Id.* at 76, Ex. JDW-15 at 6-18.[513] This change impacts the float for fuel and for Other O&M amounting to approximately $290,000. The ALJs recommend accepting EGS's revision. We find that the Babcock and Wilcox invoice referred to by Mr. Pous, Schedule JP-25, was paid seven days early to take into account check float of seven days.

The next adjustment Cities propose to the "$100,000 and over" range involves Aetna Health Insurance wire transfers. EGS has a self-funding medical and dental insurance program administered by Aetna. Entergy reimburses Aetna for the claims made by employees. According to Mr. Pous, the EGS analysis assumes the date it received the invoice from Aetna is the date service was provided. This ignores that the payment to Aetna is reimbursement for medical and dental claims submitted by active employees, who did not incur the expense the same day they submitted their claims. Mr. Pous argued that in order for the Company's analysis to be correct, Aetna would have had to pay each medical service provider on the same day the medical service was provided and then also transmit the claims to the Company that day. Mr. Pous suggested that to correct the problem the ten Aetna invoices should be eliminated. The result would be to increase the 7.61-day period to 10.18 days. Cities Ex. 104 at 106-109.

[513] EGS Ex. 148 at 75. Included also is correction of an error due to human error not due to spreadsheet logic as assumed by Mr. Pous regarding check number 25969.

EGS claims the point of service is the date Aetna pays the claims, not the date of treatment. EGS Ex. 148 at 90. The ALJs disagree with this perspective. If EGS were administering the program itself, the point of service would be the medical treatment date. Just because EGS uses a service company to pay its bills does not necessarily mean it should be allowed to use a different date than would be reasonable if there were no service company. Further, considering the fact that there is a service company and a vendor providing medical service to the employee (doctor, clinic, hospital), the date of service could be considered as the date the employee receives the treatment. It is the definition of "service" that is disputed. On balance, the ALJs conclude that the medical service provider is the relevant entity, meaning service occurs when the employee receives treatment; therefore, we find Cities' analysis most accurate.

(4) Cities claim the Company failed to recognize the one-year service period required of employees associated with payments to the Company's Thrift Plan.[514] Mr. Pous testified that the Company incorrectly recognized the time period between the prior month's employment service for its employees (i.e., ½ of a month) through the time it paid the funds to the Thrift Plan in the following month. All full time eligible employees are eligible after one year of service. The Company's analysis ignores this one-year period. The impact is to increase the 7.61 days to 44.12.

Mr. Wright testified that the Company does not accrue Thrift Plan payments as a cash expense prior to payment. It accrues the expense on the books in the month when the invoice is received from the Trustee, which results in a lag of 17 to 20 days. EGS Ex. 148 at 91. The ALJs conclude that this is the same argument used regarding vacation expense. Applying the same rationale discussed above, it is proper to count the lag based not on the accounting but on the employees' one-year employment period as calculated by Mr. Pous.

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[514]The Thrift Plan is a regular savings by employees as identified in Schedule G-2, page 12. Cities Ex. 104 at 109-110.

Conclusion: Because EGS already excluded the NISCO payments, we conclude that amount, \$643,000, should be deducted from Mr. Pous' recommended adjustment to Other O&M over \$100,000 of \$11,889,531.[515] In addition, the amount for nuclear double-counting, \$785,326, which we concluded was not counted twice, should be deducted. The total ALJ recommended deduction for Other O&M over \$100,000 is \$10,461,205, which should be subtracted from the Company's revised cash working capital

In addition, Mr. Pous recommended an adjustment to the "\$50,000 to \$100,000" range of Other O&M. Because the same situation occurs with these expense items as with the over \$100,000 range discussed above, the ALJs recommend adopting Mr. Pous' \$1,120,307 deduction in this category. The total ALJ-recommended Other O&M cash working capital adjustment is a negative \$11,581,512.

d. **Big Cajun**

EGS requests \$3,682,669 of positive cash working capital for Big Cajun expenses. Mr. Pous disputed the Company's payment pattern for these monthly expenses. In response, EGS made two adjustments. One affects the lead in coal payment and transportation costs billed to Cajun late in the month, but not paid by Cajun nor billed to EGS or paid by EGS until the first week of the following month. The other reflects the lead in payment of monthly costs which are trued-up in the first week of the second following month.

The Company revised its original request downward to \$2,946,889, which the ALJs recommend the Commission adopt. The Company argues that the costs associated with Big Cajun occur daily, and the payment pattern used by EGS complies with the Operating Agreement for that

[515] *See* Cities Ex. 104 at 110, l. 19.

plant. Payments are to be paid in the month in which the operating account disbursements are to be made by Cajun. These costs would not be recorded correctly at month end as prepayments as Mr. Pous suggests.[516]

e. Statement of Financial Accounting Standards (SFAS) 106

EGS requests cash working capital of $922,475 for these expenses. EGS's assumption is that the employee provides the product or service necessary to earn the subsequent month's payment for SFAS 106 expense in the month in which the employee works. The implication is that the payment is made immediately upon the end of the month in which an employee has worked. According to Mr. Pous, an employee must work ten years before being eligible for SFAS 106 payments upon retirement, but the Company ignored this requirement.[517] Removing employees younger than 45 years and those without ten years of service and providing a calculation based on five years, Mr. Pous found a 1.27-year lag and about $11.1 million rate base reduction.

Mr. Wright stated that Mr. Pous ignored the cash payment of SFAS 106. EGS deposits the payments each month with the Trustee under the mandate of P.U.C. SUBST. R. 23.21(b)(1)(H) for irrevocable external trusts. For Mr. Pous to be correct, EGS would have to accrue the expense and retain the funds for a ten-year period modified to reflect only the cash portion of SFAS 106 costs to 1.27 years.

While the ALJs agree that EGS makes cash payments to the Trustee each month, it is not clear from the evidence that EGS takes into account the eligibility requirements as did Mr. Pous, who does appear to have included the current cash payments in his calculation. Furthermore, this

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[516]EGS Ex. 148 at 93-95; Cities Ex. 104 at 112-114.

[517]Cities Ex. 104 at 114-115; Schedule JP-27.

expense is similar in nature to the vacation expense discussed above. Therefore, we recommend the reduction offered by Cities of $9,739,337, found at Cities Ex. 104, Schedule 15, line 11.

G. <u>Fuel Inventories</u>

1. Coal

EGS included $13,914,774 in working capital for coal inventory in rate base.[518] Staff witness Jay Curtis found that number to be excessive and recommended that EGS include $8,902,457 worth of coal inventory, which represents approximately a 35-day supply of coal at each plant: Nelson 6 (385 megawatts); and Big Cajun II, Unit 3 (227 megawatts). Both plants receive coal from mines in the Powder River Basin coal fields near Gillette, Wyoming. GC Ex. 30 at 3-4. EGS agreed with Mr. Curtis' adjustment. EGS Brief at 12. The ALJs recommend adopting Staff's recommended level of coal inventory.

The Commission's rules require the working capital allowance be composed of, but not limited to, the following:

> Reasonable inventories of materials, supplies, and fuel held specifically for purposes of permitting efficient operation of the utility in providing normal utility services. This amount excludes appliance inventories and inventories found by the Commission to be unreasonable, excessive, or not in the public interest.[519]

Mr. Curtis testified that the correct level of inventory is different for each generating station, and the goal is to strike a balance between sufficient stockpile levels to protect against plant outages and excessive stockpile levels which result in excessive carrying costs to ratepayers. GC Ex. 30 at 13. EGS's policy is to maintain a minimum of 150,000 tons and a maximum of from 350,000 to 450,000

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[518]Schedule WP/P RB 5-5.

[519]P.U.C. SUBST. R. 23.21(c)(2)(B).

tons, or a 19-days to 44-56 days' supply at Nelson 6. The policy allows 80,000 to 130,000 tons, or 24- 39-days' supply at Big Cajun. EGS Ex. 117 at 13.

EGS's requested supply equates to 45 days of fuel for EGS's share of Nelson 6 and 75 days for Cajun. Mr. Curtis recommended a 35-day supply at each plant, based on a 100 percent burn rate. Current inventory levels nationally range from 20 to 45 days' supply. But, Mr. Curtis testified there are areas of uncertainty which make EGS's 30-day target somewhat risky for EGS. These include recent railroad mergers and possibilities of extended disruptions to barge movements to the Cajun plant. To cover these uncertainties, Mr. Curtis recommended increasing the inventory level to 35 days' supply of coal, which totals $8,902,457. GC Ex. 30 at 15-17, Schedule 2.

OPC witness Eileen Pitchford addressed this issue and recommended a $5,924,991 decrease from EGS's requested amount, for a total of $7,989,783. Ms. Pitchford's adjustment is based on factors including Entergy's decision not to fully load Big Cajun 2 at all times when it was available and Cajun Electric Power Cooperative's refusal to allow EGS to receive energy from EGS's share of the unit for part of November and December 1994. Ms. Pitchford based her recommendations on 31 days of coal stockpile. OPC Ex. 47 at 3-5.

The ALJs find Mr. Curtis' reasoning regarding the 35-day supply persuasive and recommend adopting his proposed coal inventory levels.

2. Gas

EGS requests a natural gas inventory working capital allowance of $8,542,533.[520] Staff witness Larry Reed agreed this request is reasonable. This is an inventory value equal to EGS's

[520]Schedule WP/P RB 5-5; this is a 13-month average. The 12-month test year amount was $6,703,129 representing 416,054 barrels.

13-month actual inventory average ending June 30, 1996. EGS has two Texas gas generating stations, Sabine and Lewis Creek, and gets its natural gas supply from the Spindletop gas storage facility through a transportation agreement with Sabine Gas Transmission Company. The amount of inventory would supply Sabine Station with five days of fuel at full load. GC Ex. 29 at 10.

No other party presented evidence on this issue.[521] The ALJs recommend adopting EGS's requested level of working capital for its gas inventory.

3. Oil

EGS requested a fuel oil inventory working capital allowance of $6,744,663. Only Staff reviewed this request, and Mr. Reed recommended a total fuel oil inventory value of $4,931,735, consisting of 10,770 barrels of Number 2 fuel oil and 307,540 barrels of Number 6 fuel oil. GC Ex. 29 at 15. EGS did not oppose this adjustment. EGS Brief at 12. Based on the following discussion, the ALJs recommend disallowing $4,659,033 of EGS's request and including the difference, $2,085,630 of fuel oil working capital in rate base.

Mr. Harrington testified for the Company that fuel oil inventory provides supply reliability in the event of gas supply disruptions. The Company inventories greater quantities of fuel oil if the delivered price of gas is expected to be greater than the delivered price of fuel oil. EGS Ex. 89 at 13.

Cities oppose adopting Mr. Reed's recommendation, which amounts to 107,058 barrels of fuel oil for the Sabine Unit 5 and 200,482 barrels of No. 6 for the Willow Glen unit. At the Sabine

[521]In reply brief, Cities argued that EGS did not prudently use the Spindletop gas storage facility during the February 1996 cold spell. It burned "excessively priced" spot gas rather than prudently using the lower cost storage gas. Cities Reply Brief at 5; Tr. 7913. The ALJs suggest this issue is appropriate for a fuel reconciliation proceeding, as the issue has not been addressed in the revenue requirement phase of this case.

plant, this represents a 4-day burn.[522] For the last five years, the largest monthly burn has been 157 barrels, and the Company has used 1,975 barrels for the entire five-year period. During the February 1996 "Arctic blast," when gas supplies were interrupted, EGS burned no fuel oil at Sabine Unit 5.[523] The only oil used at Sabine was for ignition purposes. Tr. 7924. Cities conclude there is no need to include more than 1,975 barrels in rate base to provide sufficient ignition fuel for the Sabine Unit. Cities Reply Brief at 5-6.

Mr. Reed testified further that EGS should have burned No. 6 fuel oil at Sabine during the February 1996 Arctic blast, because gas prices were so high and it would have been prudent for the Company to have done so. Nevertheless, Mr. Reed stated at hearing, "[I]t's my impression at least that the gas or the oil that is shown on LDR-4 for Sabine station it appears to me by the prices associated with it that that is all their ignition fuel at that station, and that would be No. 2. I don't really see where it looks like they burned any No. 6 oil at Sabine for sustained operation under fuel oil burned." Tr. 7924.

Number 2 fuel oil is normally burned for ignition purposes and flame stabilization only.[524] Rate Filing Package Schedule E-3.1, pages 2-6 indicate that all the burns at Sabine reflected in Mr. Reed's Ex. LDR-4 were for ignition and start-up. Furthermore, there is no evidence that EGS burned any No. 6 fuel oil at the Willow Glen station. Schedule E-3.1 at 26 & 27 shows curtailment burns at Willow Glen in 1992 and 1996, in addition to ignition and start-up burns at other times. The schedule does not indicate what type of fuel was burned during the curtailments. However, the

[522]GC Ex. 29 at LDR-1; Tr., Reed, 7913-7914.

[523]GC Ex. 39 at LDR-5; Tr. 7915.

[524]Schedule E-2.3, note 4.

prices per MMBtu listed on LDR-4 appear to be the same or similar for ignition as they are for curtailment. Therefore, the ALJs find, as did Mr. Reed on cross-examination, that all the fuel oil burned at both plants was No. 2 oil. No evidence exists to show that any No. 6 fuel oil was burned.

General Counsel states that based on Mr. Reed's analysis of EGS's historical fuel oil burns from 1991 through June 1996, "EGS can reasonably expect to meet its fuel oil needs at the coal-fired generating stations with Mr. Reed's recommended levels of *Number 2* fuel oil." GC Brief at 17. The ALJs find no justification in the evidence to include any No. 6 fuel oil for Sabine and Willow Glen in rate base. It appears that the No. 2 fuel oil supply has been sufficient to cover any back-up fuel oil needs at these gas plants. Total No. 6 fuel oil equals $4,659,033. GC Ex. 29 at LDR-1.

H. Materials and Supplies Inventories

EGS requests $89,452,000 attributable to its materials and supplies inventory.[525] Staff and OPC recommend amounts close to this. The ALJs recommend the Commission adopt a $88,527,930 inventory based on OPC's adjustments.

EGS's request represents a 13-month average inventory, adjusted for gas and steam inventory and NISCO-related amounts, as of test-year end.[526] Staff witness Debbie Witbeck reduced that amount by $4,218,000 using the most recent 13-month data (through November 1996). She also restated materials and supplies to account for a change in the level of expense that EGS will incur due to a recent reimbursement agreement with NISCO. OPC witness Mr. Allen reduced the EGS request by $924,070 to account for items that are obsolete.[527]

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[525]Schedule B-1, line 6.

[526]Schedule J-1, page 2 and E-1 UPDATE.

[527]OPC Ex. 48 at 26, Ex. RMA-1, Adjustment No. 16; RFP Schedule E-1.2.

In rebuttal, EGS witness Mr. Wright noted that Ms. Witbeck's changes do not comport with the post-test-year adjustment rule related to plant in service and should be ignored. EGS Ex. 148 at 45. The rule permits post-test-year adjustments to decrease rate base (a) if the plant was recorded in FERC Account 101 or 102; (b) if the plant was held for future use; (c) if there is construction work in progress; or (d) if there is an attendant impact of another post-test-year adjustment.[528] None of these circumstances exists regarding materials and supplies.

General Counsel argues that Ms. Witbeck's adjustment is not a post-test-year adjustment. He states that the Commission used a 13-month average which was subsequent to the test-year end in Docket No. 7510.[529] EGS responds that the substantive rule was adopted after Docket No. 7510[530] and is, therefore, not precedent for this case. Further, the rates in this docket are retroactive to June 1996. EGS argues that retroactive application of prospective changes to account balances will further distort the test-year foundation of the ratemaking process. EGS Reply Brief at 13.

The ALJs find that the substantive rule applies and Staff's post-test-year adjustment does not qualify. OPC's adjustment is appropriate given the fact that the materials and supplies became obsolete during the test year. Tr., Wright, 9239. It is, therefore, not a post-test-year adjustment, even though EGS may not have removed the amount from its books during the test year. As OPC argues, ratepayers may find themselves paying for obsolete inventory indefinitely, if for some reason the Company did not write obsolete inventory off its books expeditiously. OPC Brief at 11. The ALJs recommend adopting OPC's adjustment resulting in a materials and supplies working capital inventory balance of $88,527,930.

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[528]P.U.C. SUBST. R. 23.21(d)(2)(G)(iii), GC Brief at 17.

[529]*Application of West Texas Utilities Company for Authority to Change Rates*, Docket No. 7510, 14 P.U.C. BULL. 620 (Nov. 30, 1987) [hereinafter Docket No. 7510].

[530]EGS references 21 Tex. Reg. 6453-6455 (July 12, 1996).

I. Deferred Sales Tax on Coal Cars

EGS included in rate base $317,000 related to deferred sales tax on coal cars which is a 13-month average.[531] General Counsel recommends the test-year-end balance of $291,000. Mr. Wright testified that the Company does not oppose using the year-end balance as long as Ms. Witbeck's other adjustment to injuries and damages, coal car maintenance, customer deposits, and contractor retainage also are based on year-end balances. EGS Ex. 148 at 45. The Commission normally uses 13-month averages only for those rate base items subject to great volatility. GC Ex. 35 at 16.

EGS defers the sales taxes and amortizes them to coal inventory over a 20-year period.[532] In EGS's last three rate cases, it requested and was granted test-year-end treatment for this item. Further, Ms. Witbeck testified that this account simply reflects the original deferred sales taxes approved and the subsequent amortization of that amount. Taking a thirteen-month average distorts the actual unamortized balance at test-year end. *Id.* at 15.

The ALJs find Ms. Witbeck's reasoning persuasive and recommend adopting Staff's adjustment resulting in a deferred sales tax of $291,000 for the test year.

J. Property Insurance Reserve Balance

EGS requests a 13-month average for the reserve balance for property insurance of ($14,112,000).[533] It seeks to increase the Texas jurisdictional property insurance accrual to bring the

[531]Schedule WP/P RBS1; WP/P RB 11-1.

[532]This was approved by the Commission in *Application of Gulf States Utilities Company for Authority to Change Rates,* Docket No. 4510, 8 P.U.C. BULL. 51 (Oct. 22, 1982)(mem.) [hereinafter Docket No. 4510].

[533]Schedule G-15, page 15, line 110.

target reserve balance to ($18,000,000). GC Ex. 35 at 18. The ALJs recommend adopting Staff's balance for property insurance of ($15,572,000), or ($12,075,000) on a Texas retail basis.[534]

Ms. Witbeck recommended the test-year-end balance of ($15,572,000) be included in rate base which represents a ($1,460,000) increase to the reserve balance requested by EGS. She stated that only the working capital components are eligible for the application of a 13-month average. The actual end of the test year should be evaluated to determine whether the reserve balance is appropriate to cover the Company's expected future losses, but the assessment should be based on the actual reserve balance, not a 13-month average. *Id.*

EGS does not oppose Staff's adjustment, but argues that the insurance reserve balance should also be adjusted to reflect the reduction of the reserve after the 1997 ice storm. The property insurance reserve balance has apparently been reduced due to the 1997 ice storm and is now $1,780,000.[535] EGS did not adjust this in its schedules, as it is likely not an appropriate post-test-year rate base adjustment under P.U.C. SUBST. R. 23.21(d)(2)(G)(iii). If the Commission changes the amount of insurance expense going to the reserve account to reflect the 1997 ice storm, then it should reflect this rate base change, as well. The ALJs recommend no change to current level of insurance expense collected for the reserve fund. The ALJs discuss the property insurance matter in the cost of service portion of this PFD.

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[534]This differs from the reserve balance Cities found existed at test-year end of ($11,410,000) discussed in Section VII.A.5. below.

[535]EGS Ex. 148 at 46; *See* EGS Ex. 142, Wilson Rebuttal, at 2.

K. Proposed Adjustments to Invested Capital

1. Amortization of Deferred Financing Costs

EGS requests a net increase in amortization expense of $5,196,419.[536] In rebuttal testimony, the Company agreed with the General Counsel's proposed amortization period end of January 31, 2000 recalculated assuming rates are retroactive to June 1996. 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.[537] The ALJs recommend adopting EGS's revised request based on the new amortization period.

Cities argue against this change in amortization period. However, as EGS noted in brief, the Company does not seek a change in the rate base amount of deferred financing costs to be amortized, which amounts were approved in prior Commission dockets. EGS Reply Brief at 14. The ALJs reject Cities' position at Section VII.C.2. below.

2. Cost Savings Expenditures in Rate Base

The Company added $31,439,000 to rate base for its expenses in developing cost savings related to the merger. Parties generally recommend that all such costs be disallowed. Based on the discussion at §VII.A.8. below, the ALJs recommend no amount of expenditures to reduce cost savings related to the merger should be included in rate base.

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[536] *See* discussion at §VII.C.2. below regarding amortization expense in cost of service.

[537] EGS Ex. 148, Wright Rebuttal, at 51-52; Ex. JDW-14.

3. Prepayments -- Post-Employment Benefits Other Than Pensions (OPEBs)

Cities determined that EGS's requested level of OPEB prepayments is incorrect because EGS failed to reflect any funds collected from ratepayers in its RFP. The rates set in Docket No. 12852 were effective March 31, 1994. From April 1994 through the end of the test year, June 1996, EGS was authorized to collect $36,205,679 on a total Company basis for OPEB expense. None of this, according to Cities, has been reflected as an offset to the Company's OPEB request. Cities Ex. 104 at 54-55.

Mr. Pous testified that the Company used an actuarial analysis to support its OPEB expense request. The market value of assets funded reflected in that analysis is zero. That analysis also reflected information as of January 1, 1996, showing no fund balance, and EGS did not make its first payment for OPEB expense into the required external trust fund until May 31, 1996. *Id.* at 55, Schedule JP-7. In other words, EGS collected from ratepayers the amount of OPEB expense allowed in Docket No. 12582, but EGS did not account for some 27 months of cost-free capital in its rate request in this docket.

In rebuttal, Mr. Wright testified that the Company collected those funds from ratepayers only in its Texas jurisdiction. Therefore, the amount deposited to the external fund in May 1996 was $14.462 million, of which $13,932,403 is the Texas retail incremental amount and $529,399 represents the interest required by P.U.C. SUBST. R. 23.21(c)(1)(H)(v). EGS Ex. 148 at 98. The rule states:

> Deposits on the fund shall include, in addition to the amount included in rates, an amount equal to the fund earnings that would have accrued if deposits had been made monthly.

The $14.462 million is the amount contributed from April 1994 through December 1996.

EGS argues that no OPEB prepayment funds should be included in rate base because the funds actually went into the external trust, plus interest for the period during which prepayments occurred. Cities claim this is irrelevant, because typically an adjustment is made in the OPEB actuarial analysis to account for the provision of funds by ratepayers. Cities Reply Brief at 6. Furthermore, that interest deposit benefits employees through the trust but does not recognize that the ratepayer should be credited for providing the cost free capital to the Company. Moreover, EGS acknowledges that a prepayment exists in the amount of $30,743,301 total company.[538] EGS Ex. 148 at 97. Mr. Pous determined that the rate of return permitted in Docket No. 12852, 10.05 percent, should be applied to the amount collected. Cities Ex. 104 at 57.

The ALJs conclude that the Company is correct. It has not had access to the funds for any purpose, including to fund rate base. Therefore, a deduction would not be an offset to a rate base item. EGS's requested prepayment balance should not be reduced by its OPEB funds. However, the ALJs are concerned that the amount deposited into the external fund may not reflect the amount the fund would have accrued if deposits had been made monthly. It seems that $529,399 is not enough, but the ALJs have no way of calculating the amount based on deposits over the 27-month period. Therefore, we hereby order the Company to provide those calculations with its exceptions to the PFD. The Company should indicate what interest rate it applied to the funds it retained from April 1994 through May 1996 and how it calculated the interest based on the OPEB ratepayer payments each month. Any excess interest above that $0.5 million invested in the external trust should be credited to rate base in this docket. With this calculation, the Company should justify the interest rate it used as a reasonable proxy for that which the trust funds would have earned.

If the Commission disagrees with any of this, the ALJs recommend it calculate the rate base reduction based on the Texas jurisdictional amount received by EGS as reflected on Schedule G-2.2

[538]This amount results after expenditures on a current payment, or pay-as-you-go basis.

UPDATE, EGS Ex. 148 at Ex. JDW-18, page 2 of 2, multiplied by the 10.05 percent return as Mr. Pous suggests at page 57 of his testimony. He assumed earnings would be based on an average monthly balance which would include compounded interest from April 1994 through May 1996.

4. Other Adjustments

Staff witness Ms. Witbeck proposed several adjustments to rate base for balances for injuries and damages, rail car maintenance reserve, customer deposits, and contractor retainage–totaling $297,000–to reflect using test-year-end balances instead of 13-month averages as EGS had done. GC Ex. 35 at 22. EGS does not oppose these adjustments. EGS Ex. 148 at 45. The ALJs therefore recommend the Commission adopt the following Staff adjustments:

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

VI. Cost of Capital

A. Cost of Equity

The only contested element of cost of capital is the appropriate return on equity (ROE) for EGS. The parties' recommendations are represented in the following chart:

	EGS	Cities	OPC	General Counsel	TIEC
Range:	12-13%	10-11.25%	10.65-11.05%	11.7-12.7%	9.65-13.94%
Reasonable Return	12.75%	10.62%	10.8%	12.2%	11.20%

The ALJs recommend a ROE range of 11.2 percent to 12.2 percent and suggest the Commission adopt the mid-point, 11.7 percent.

All parties employed the discounted cash flow (DCF) methodology to derive an ROE. EGS and Staff used a non-constant growth DCF model, while Cities and OPC used the constant growth DCF; TIEC applied both non-constant and constant methods. All parties except Cities also incorporated a risk premium analysis in the above proposed rates.

The DCF models attempt to replicate the market valuation process employing the theory that the price of a share of common stock is equal to the present value of the expected cash flows (dividend and stock price) that the investor will receive while owning the stock.[539] This is discounted at the investors' required rate of return. EGS Ex. 87, Fairchild, at 30-31. The dividend yield is the ratio of the dividend rate to the stock price. In calculating the dividend yield, the key guideline is that the yield not be distorted due to fluctuations in stock market prices. Therefore, it is important for the analyst to select a time frame for measuring yield that will be representative of the rate year. Most dividends are then increased by a growth rate factor to arrive at a forward-looking dividend. Cities Ex. 102 at 61.

[539]The DCF methodology is derived from the Gordon dividend growth model to be used as a tool for determining the value of a share of common stock. GC Ex. 39 at 18.

1. Fundamental Concepts

Certain fundamental concepts underlie these analyses, *i.e.* determining what is the investors' expected return on common stock of Entergy Corporation (EGS does not trade common stock); and determining what assumptions put into the model would capture those investor expectations. Mr. Darryl Tietjen, testifying for Staff, explained succinctly the three principal assumptions underlying the DCF model:

> First, investors evaluate the expected risk and expected cash flows of all securities in the capital markets, and through the trading process, adjust the price of each security so that the expected return is commensurate with the expected risk.
>
> Second, investors discount the expected cash flows at the same rate in every future period.
>
> Third, dividends, rather than earnings per se, constitute the source of value for a share of stock. Absent a sale of the stock, dividends are the only cash flows received by investors. Earnings, however, are critical because they make it possible to pay dividends, and the level of earnings ultimately determines the level of growth in the company and in dividends over time.

GC Ex. 39 at 22. Issues relevant to return on equity are discussed below.

a. <u>Constant vs. Non-Constant Growth DCF</u>

The constant growth model assumes that the growth rate for both dividends and earnings remains constant, and other factors also remain constant--book value and price; earned rate of return on book value; price-earnings ratio; discount rate (no changes in risk or interest rate levels). Dr. Fairchild, testifying for EGS, and Staff witness Mr. Tietjen fault the constant-growth model because its assumptions do not match the recent and future unstable electric utility industry.[540] The constant growth is based on past experience, which Dr. Fairchild testified is not indicative of what investors expect from utilities over the longer term. Near-term growth will be modest, but after deregulation, regulated utilities will parallel competitive firms. The constant growth DCF model assumes that historical experience or the near-term growth projected by security analysts will continue into perpetuity. Mr. Tietjen testified that at present the "specter of increasing competition makes the constant-growth assumption implausible." Thus the model is ill-suited to accommodating significant differences between near- and longer-term expectations.[541]

Some parties contend that the constant-growth model incorporates investor expectations about stock prices and risk associated with competition, because such risks are incorporated in the stock price and consequently in the constant-growth model.[542]

The ALJs acknowledge that to the extent the constant growth DCF model captures investor expectations it has value. However, to the extent it projects market risk or diversity unchanged from historical fact, then we conclude it is deficient. The only witness to look at both sides is Mr. Gorman, whose testimony is discussed in more detail below.

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[540]EGS Ex. 87 at 34-35; GC Ex. 39 at 19.

[541]GC Ex. 39 at 21; *See also* EGS Ex. 87 at 39. The notion is that constant-growth DCF model fails to account for possible deregulation and competition. *See* GC Ex. 39 at 21. The Commission apparently rejected this notion in Docket No. 12852, Order on Rehearing at 6 and Attachment 1 at 5, deleting the ALJ's proposed Finding of Fact No. 33 which stated that the constant-growth DCF should not be used because it was not reasonable to assume that the growth rates of a regulated monopoly will remain stagnant as that monopoly shifts to a competitive market.

[542]Cities Brief at 20. *See also* Tr. 6930-6931 (Lawton); EGS Ex. 87 at 30; Tr. 5453-5454 (Fairchild); GC Ex. 39 at 22; Tr. 8281 (Tietjen); Tr. 7745 (Szerszen).

i. Multi-Stage DCF

The ALJs find that the multi-stage non-constant DCF analysis is the most likely model for projecting dividend payouts and future growth. The two-stage DCF assumes only two discrete growth rates and does not capture the expectations about the transition period as the industry moves toward competition. The multi-stage DCF model assumes that investors expect electric utilities to be separated into regulated (largely the T&D) segments and unregulated (generation) segments. It further expects the unregulated segment to be fully competitive in 10 years, with a transition period between 2001 and 2006. And it assumes that investors expect each segment to grow at different rates, the unregulated segment being similar to that of a competitive firm. EGS Ex. 87 at 42-43. These are the models EGS, Staff, and TIEC used in their analyses.

Based on the literature, evidence in this case, and apparent trends in the various legislation, it appears to the ALJs that the assumptions just discussed and put into the multi-stage DCF model are legitimate at this stage of the movement toward deregulation. The ten-year time table for full competition is uncertain. All sources predict different time periods ranging from four years to ten years. *Id.* at 45-46. No one can actually foresee, but it is reasonable to assume that a ten-year horizon is more likely than an earlier time frame, and currently a certain amount of risk associated with the transition is included in investor expectations about return on their investments.

ii. Comparable-Company DCF

The parties prepared a DCF analysis of Entergy Corporation. This is appropriate because investors buy Entergy stock; EGS has no publicly traded common stock, and there is no market data for EGS.[543] One could assume the investor considers the fact that Entergy has five electric operating

[543]EGS Ex. 87 at 48; GC Ex. 39 at 24.

companies, a nuclear plant, and fifty some unregulated subsidiaries who engage in a variety of mostly utility-related businesses. Mr. Tietjen found that EGS accounts for about one-fourth of the Entergy assets, and opined that EGS is a major part of the risk of Entergy. GC Ex. 39 at 25. All Entergy operating companies have minimum-grade investment ratings. *Id.* at 10.

Cities and OPC argue that captive ratepayers should not be required to assume the risk of diversification into unregulated business and foreign investment--the projected growth rates for Entergy reflect Entergy's aggressive development of unregulated ventures. As a consequence, Cities aver that EGS's ROE cannot be greater than Entergy's. Cities Brief at 16. The ALJs find this to be conceptually reasonable. Entergy projects that its unregulated investments will account for 30 percent of consolidated earnings by 2000, and the contributions from diversified businesses should be the main driver for seven to eight percent earnings growth over the next four years. Entergy has targeted an equity return of 15 percent from its foreign utility investments. OPC Ex. 49 at 16. It is difficult to determined how this diversification affects investor expectations, but the ALJs conclude that it is certainly a factor and may contribute to the overall perceived risk attendant to the Entergy companies.[544] If that is true, then ratepayers pay an ROE that ultimately underwrites to some degree Entergy's unregulated ventures and underwrites any improved competitive position related to those ventures.

The range of reasonableness resulting from the Entergy-specificDCF analysesis 10.0 percent to 11.78 percent.[545] The ALJs, therefore, must conclude that even though EGS's triple-B minus

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[544] *See* GC Ex. 39 at 8-12. Mr. Tietjen explained that Entergy's aggressive overseas investment activity impacts the rating agencies' perception of Entergy and contribute to its negative and below-average ratings. The various agencies are somewhat mixed in their opinions of Entergy, but all advocate ratepayer caution.

[545] Cities point out that Mr. Gorman's analysis, the 11.78% result, considered a 13-week average stock price and failed to eliminate effects of the recent, aberrant downturn in stock prices of Texas utilities. *See* Tr. 6887-6888; 6937; 7746-7747.

credit rating is very slightly lower than Entergy's triple-B, it is the parent company's business position that drives the decision on this issue.

b. What Will Utilities Look Like and How Should Impending Competition Affect ROE?

During the transition-to-competition period, what will happen to dividends and earnings growth? An underlying assumption in Dr. Fairchild's and Mr. Tietjen's DCF models, and used by Mr. Gorman, is that following deregulation generating assets will comprise one-half of the utility's total assets.[546] Furthermore, they assume that the generation side of the industry, being subject to competition, will eventually grow at the overall market growth rate projected for the S&P 500 index. Both EGS and Staff applied the long-term growth rates to all utilities in the year 2006.[547]

Cities claim the key assumption--after deregulation utilities will consist of 50 percent generating assets and 50 percent transmission and distribution--is likely not to occur. The more likely scenario is that utilities will sell off their generating assets.[548] In further support of this notion, Cities supplied a 1996 Merrill Lynch publication, "Electric Utility Industry," which identifies California's Pacific Gas & Electric and several New England utilities that have already or are close to liquidating out of the generation business. They will do this through accelerated plant depreciation, asset sales, and asset securitization. Such liquidation will result in great reduction in risk, according to the Merrill Lynch article. Cities opine that if generation is liquidated, then growth rates should reflect the distribution and transmission business, a slower growth industry. Cities Brief at 23.

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546 EGS Ex. 87 at 47-48; GC Ex. 39 at 27; Tr. 8304.

547 EGS Ex. 87 at BHF-3 and BHF-4; Tr. 5462; GC Ex. 29 at 28; Tr. 8303.

548 EGS Ex. 87 at 44-45; GC Ex. 39 at 3 and 8; Tr., Tietjen, 8290.

What EGS in particular, or Entergy, will look like in ten years is unknown mostly because no deregulation legislation has yet passed in Texas. No single, industry-wide transition plan currently exists, and various proposals are being considered in almost all states, including when to make the move. GC Ex. 39 at 6. The ALJs find, however, that while Cities' arguments are compelling, investor blocks certainly do rely on credit agency forecasts as the most reliable source of information about growth rates. *See* GC Ex. 39 at 23. Further, it is unlikely that EGS will be able to liquidate its nuclear plant. At this point in time, a 50/50 split is a sound basis for developing the competitive picture.

c. Should a Risk Premium Be Used?

Equity risk premiums tend to vary over time as changes occur in the capital markets. Inflation acts differently on debt and equity investments. Because bond interest payments are fixed upon issuance, there is no mechanism for adjusting returns to reflect changes in inflation and purchasing power. When inflation rises, the perceived risk associated with bond investment increases, and market interest rates rise. But because stocks are viewed as a better hedge against inflation, the required return on equity will tend to rise less as inflationary fear increases than the required return on debt. Thus, the equity risk premium can be expected to fall as interest rates rise and rise as interest rates fall.[549] GC Ex. 39 at 33.

The ALJs conclude that calculating a risk premium is appropriate as a check on the DCF analysis, but it is extremely subjective--changing only slightly the assumptions underlying all of these analyses can change the results. However, we agree with Mr. Tietjen, that an impartial analyst using a risk premium approach that measures as objectively as possible the risks attendant to deregulation and the long-term effects on the utility industry will provide results as reliable as it is

[549]Mr. Gorman, however, puts another spin on this theory by removing the effect of inflation to reach a real rather than nominal interest rate and stock price.

possible to obtain. *See* discussion at Tr. 8342-8345. Therefore, the risk premium analysis should not be discounted; in fact, it may be more useful in these uncertain times than any other tool.

d. **Decline in Capital Costs Since the Last EGS Rate Case**

All parties to this docket, except EGS, proposed lower ROEs than they proposed in Docket No. 12852. This could indicate that the Company has experienced a decline in capital costs.

Docket	Cities	GC	OPC	TIEC	EGS
12852	11.9%	12.6%	11.5%	11.75%	12.75%
16705	10.0%	11.7%	10.65%	11.20%[550]	12.75%

Dr. Fairchild did acknowledge his risk premium studies indicate that, apparently due to a decline in interest rates, the risk premium has declined since EGS's last rate case. Tr. 5474-5479.

e. **Pricing at the Low End of the Reasonable Range**

PURA requires that the Commission take certain things into account in setting a reasonable return on invested capital:

(1) the efforts of the electric utility to comply with its most recently approved integrated resource plan;

(2) the efforts and achievements of the utility in conserving resources;

(3) the quality of the utility's services;

(4) the efficiency of the utility's operations; and

(5) the quality of the utility's management.[551]

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[550]*See* Cities Ex. 102 at 65; GC Ex. 39 at 38; OPC Ex. 49 at 56; & TIEC Ex. 5 at 18.

[551]PURA §36.052

Cities recommend the Commission adopt an ROE at the lower end of the reasonable range of rates because of EGS's poor service quality. They recommend a ten percent ROE. Because the ALJs do not have the service quality issues before them,[552] we decline to make an adjustment on that basis.

General Counsel recommends adoption of the low end of Mr. Tietjen's range, or 11.7 percent, to reflect Ms. Romines' and Ms. Jaussaud's recommendations regarding affiliate transaction issues and failure to achieve solid conservation resources. GC Ex. 39 at 13. Likewise, OPC would have the Commission adopt the lower end of Dr. Szerszen's range of returns, 10.65 percent, considering EGS's deficient DSM programs. OPC Ex. 49 at 56.

Between rate cases, EGS retains all non-fuel O&M savings associated with the merger. Those savings totaled $121.019 million from 1994 to 1996. *Id.* at 11. And savings projected for 1997 are $73.3 million. Considering Cities' recommendations in this case and the after tax earnings available from merger-related savings, EGS will have a pre-tax coverage ratio of about 2.9x, which is consistent with a BBB bond rating. According to Mr. Lawton, EGS "will earn about 150 basis points higher return on equity when considering the after tax impact of EGSI's share of non-fuel O&M merger-related savings." To help ameliorate this fact, Cities also recommend adopting a ROE at the low end of the range in order to keep rates down and allow EGS to become more competitive. Cities Ex. 102 at 65-66.

The ALJs conclude there should be no reduction in cost of equity to account for DSM failures based on our recommendation to deny all DSM expenses. The same is true for affiliate expense, where we recommend those costs be denied. Furthermore, a ten percent ROE for EGS, as Cities suggest, is too far below what we conclude is a reasonable range of returns.

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[552]The Commission severed those issues from the main rate case and considered them *en banc* in a separate hearing.

2. Parties' Evidence

a. EGS

Dr. Fairchild applied the multi-stage non-constant growth DCF model and a risk premium analysis in his return on equity. Dr. Fairchild's assumptions include the following:

a. the unregulated segment will be fully competitive in ten years, 2006; and

b. each segment will grow at different rates--regulated segment will reflect a conventional utility and the unregulated segment will reflect a competitive firm.

Dr. Fairchild's near-term growth (1997-2001) was based on dividends expected over the next 12 months obtained from Value Line, and then increased annually through 2001 using the five-year earnings growth forecast published by the Institutional Brokers Estimate System (IBES). For 2006 and beyond, he assumed growth for the regulated segment to be equal to that reported by IBES for the electric utility industry as a whole, and used the IBES growth rate regarding the S&P 500 companies for the unregulated segment. He weighted these growth rates equally. EGS Ex. 87 at 46-47. Dr. Fairchild interpolated the first stage and last stage growth rates to arrive at the transition stage rate.[553]

Because EGS has no publicly traded shares of common stock, Dr. Fairchild applied his DCF model to proxy firms selected from triple-B utilities rated so by Moody's and S&P. He excluded firms with no nuclear generation or which were currently involved in a merger.[554] EGS Ex. 87 at 49.

[553]Exhibit BHF-4 provides an alternative that uses dividends for 1997 and 2000 based on Value Line projections, with dividends in 1998, 1999, and 2001 being interpolated. The result is nearly identical.

[554]Dr. Fairchild used Boston Edison, Eastern Utilities Associates, Entergy Corporation, General Public Utilities Corp., PECO Entergy Company, Rochester Gas and Electric, and United Illuminating.

The results of his analysis indicated costs of equity ranging from 10.5 percent to 13.9 percent, with an average of 12.3 percent.

Dr. Szerszen criticized Dr. Fairchild's assumptions about the future of the utility industry. She explained that there is a vast array of legislative initiatives proposed in various states. They range from full recovery of stranded costs to limited recovery. Some utilities will sell off generation; others will sell transmission and distribution. Mergers could change the playing field, as will diversification. Overall, there is no assurance that a vigorous competitive market will result at all; witness the long distance telephone market with only three or four major players dominating the field. Dr. Fairchild's model incorporates diversification risk and higher growth prospects which OPC believes are inappropriate ratepayer costs. OPC Ex. 49 at 25-26.

Dr. Fairchild also applied a risk premium analysis to his DCF calculation. He relied on several studies to estimate equity risk premiums over a variety of time periods. He also assumed that equity risk premiums tend to move inversely with interest rates. *Id.* at 56-57; BHF-6. Because current interest rates are near their lowest level in 20 years, equity risk premiums are currently high. *Id.* at 59.

The results of Dr. Fairchild's risk premium analysis range from 11.17 percent to 15.04 percent. He eliminated the highs and lows and selected a range from 12.25 to 13 percent.

All other parties eschewed Dr. Fairchild's risk premium analysis. They found his cost of equity estimate to be suspect, because it is based, in part, on the same risk premium approach the Commission rejected in Docket No. 12852.[555] Of the nine studies he examined for his risk premium analysis, Dr. Fairchild discarded four as creating implausible results: the Brigham, Shome & Vinson

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[555]Docket No. 12852, Order on Rehearing at Attachment I, page 5, Finding of Fact No. 35 (May 26, 1995). The Commission found the analysis to be result-oriented and to produce unrealistic results that were too high.

1984 analysis' 15.04 percent ROE, and the Harris 14.89 percent were ludicrous. After those he eliminated the Carleton, Chambers & Lakonishok (CC&L) 13.65 and the low 11.17 percent result. Tr. 5511-5512.

TIEC's complaints are representative of other parties': The CC&L and Benore Investment Studies use data that are now very old, which cannot be a reasonable proxy for today's utility climate. The Regulatory Research Associates, Inc. (RRA) study takes the average ROE for electric utilities from 1974 to 1995 and subtracts the average utility bond yield during the same year to calculate the risk premium. Dr. Fairchild adjusted each year's risk premium by a statistical coefficient. TIEC claims this skews the results, raising the cost of equity above the actual cost of equity approved by Commissions in those same years. TIEC Brief at 8-9; Tr. 5514-5527.

The 50-year Ibbotson Associates study looks at data from 1926 to the present. Dr. Fairchild testified that any subpart of the 50-year period, such as a ten-year time frame, could yield a much different result. TIEC contends that for this reason, the Commission should use Mr. Gorman's 64 year study.

Likewise, TIEC contends that Dr. Fairchild's use of IBES growth rates, which are earnings growth rates, as a proxy for dividend growth rates is fundamentally incorrect. If earnings and dividends grow at the same rate, then the dividend payout ratio will not change. If the payout ratio does not decrease, then the company will not have the earnings necessary to sustain its long-term growth rates. Dr. Fairchild assumes that each of the stocks in his IBES DCF model will experience a 4.5 percent long-term growth rate. A company can fund its growth by retaining earnings, which causes a decrease in the dividend payout ratio--less earnings available to pay dividends. Dr. Fairchild's IBES model does not take this basic relationship into account. TIEC Brief at 4.

TIEC argues that the only other ways for a company to fund dividend growth are to borrow money, possibly by issuing additional common stock, or by earning a higher earned rate of return. Tr. 5501; TIEC Brief at 4-5. Dr. Fairchild did not discuss either of these scenarios. He testified that within the context of his DCF model, in order to reach the dividend growth rate he used, without retaining earnings, the Company must have a *realized* rate of return of 16.7 percent. Tr. 5506. TIEC finds such a rate implausible; therefore, it opines Dr. Fairchild assumed that to achieve the growth rate there must be a decrease in the dividend payout ratio. But, because he uses the earnings growth rate as a proxy for the dividend growth rates, the payout ratios of each of his comparable companies will not change, and the growth rates he posits cannot be achieved. TIEC concludes that Dr. Fairchild's IBES model is therefor unreasonable. TIEC Brief at 7.

In rebuttal, Dr. Fairchild defended his risk premium analysis, based on historical measures, saying that even though competitive risks were absent in the past, equity risk premiums based on historical relationships would likely understate the return currently required by investors. Therefore, his conclusions were a conservative measure of the investors' required return. EGS Ex. 137 at 7.

b. General Counsel

Staff witness Darryl Tietjen performed a multi-stage non-constant growth DCF analysis which produced a DCF ROE of 11.7 percent for EGS. His model uses short-term, intermediate-term, and long-term periods. He used dividend projections provided by Value Line, Goldman Sachs, Merrill Lynch, and Zacks Investment Services (Zacks). These firms factor into their projections such information as general economic projections, impact of new legislation, regulatory actions, and technological advancements. GC Ex. 39 at 22-23.

Mr. Tietjen used as comparable companies those with triple-B credit ratings; electric revenues constituting at least 70 percent of total revenues; no recent dividend cuts or omissions; at