VEMCO Legal Fees

248. In its November 9, 2012 Errata filing, SWEPCO removed from its requested cost of service a $19,899 invoice from Stone Pigman Walters Wittmann, which is associated with the Valley Electric Membership Corporation (VEMCO) acquisition and was inadvertently included in SWEPCO's requested cost of service. SWEPCO does not oppose Staff's recommended adjustment of $19,899 to SWEPCO's requested cost of service for this item.

Customer Choice Costs

249. SWEPCO does not oppose Staff's recommended adjustment of $14,179 to SWEPCO's requested cost of service.

Intangible Asset Amortization Expense

250. Intangible plant is captured in FERC Account 303 and consists of the cost of patent rights, licenses, privileges, and other intangible property necessary or valuable in the conduct of utility operations.

251. SWEPCO's intangible plant and associated amortization is comprised of computer software costs such as its customer billing system.

252. Due to the growth in computer applications, investment in computer software grew significantly since FERC established Account 303 in 1989.

253. SWEPCO's amount of intangible plant is in line with that of other utilities.

254. This amortization is properly captured in FERC Account 404 – Amortization of limited term electric plant, which includes amortization of licenses and patent rights.

255. SWEPCO's test-year intangible asset amortization expense is an element of SWEPCO's reasonable and necessary test-year operating expenses.

Weather Normalization

256. Weather data is not randomly distributed by year. There can be weather trends.

257. The use of a 30-year period for normalizing weather is not a reasonable means of capturing such trends.

258. The use of 10 years of data is a reasonable means of capturing such weather trends.

259. The weather normalization adjustment should be applied to kilowatt hour (kWh) billing units instead of as a revenue adjustment.

260. The weather adjustment would be $828,345 less than what SWEPCO used for the 30-year normalization.

Residential kWh Growth in the Post-Test-Year Adjustment

261. SWEPCO filed a post-test-year adjustment to the billing determinants to correspond with the post-test-year plant adjustments to account for the expected growth in customer count and usage that occurred between the end of the test year and the time the Turk plant became operational at the end of 2012.

262. Four major items caused the historical residential growth to be higher than the forecasted period: weather, the addition of the former Texas North Company customers into SWEPCO's service territory, weakened economy, and changing energy efficiency standards and saturations.

263. Because SWEPCO has actual data for the first 11 months showing that the weather-normalized residential sales have come in 5% below the forecast that was used in the post-test-year adjustment, it reasonable for SWEPCO to replace the forecasted residential sales post-test-year adjustment with the actual weather-adjusted 2012 sales. SWEPCO should use the 10-year weather normalization.

Lighting Allocation

264. SWEPCO's rebuttal production demand allocator appropriately reflects 8,760 hours for all classes.

Residential Customer Unit Costs

265. SWEPCO's class cost-of-service study appropriately functionalizes and allocates all costs incurred by SWEPCO in support of its utility operations following established cost-causative factors and practices. A component of these costs includes general overhead costs, which are properly recorded in support of SWEPCO's overall utility operations, including customer costs.

266. SWEPCO proposes to allocate transmission costs to retail classes based on the 12 Coincident Peak (12CP) demand allocator.

267. The 12CP method allocates costs based on peak demands in all twelve months, with no distinction between the on-peak summer months and the off-peak months.

268. SWEPCO is a summer peaking utility. The electricity demands in the spring and fall months are much lower and not relevant in determining the amount of capacity needed for SWEPCO to provide reliable service.

269. The June through September summer peak demands determine the amount of transmission capacity that SWEPCO must build. SWEPCO's use of the 12CP method is inconsistent with cost causation.

270. The Commission has a longstanding policy of allocating transmission costs based primarily on peak demands in the four summer months.

271. The Average and Excess/4 Coincident Peak (A&E/4CP) method for allocating transmission costs to the retail classes is standard and the most reasonable methodology.

272. SWEPCO should use the A&E/4CP method for allocating transmission costs to the retail classes.

Municipal Franchise Fees

273. Municipal franchise fees are taxes levied by municipalities based on the amount of electricity sold within the municipal boundaries.

274. SWEPCO proposes to allocate and collect municipal franchise fees from customer classes based on in-city kWh sales.

275. Municipal franchise fees are caused by the kWh delivered within incorporated municipalities that levy these costs. The cost of municipal franchise fees should be directly allocated to customer classes based on kWh delivered within the municipal boundaries.

276. Collection of municipal franchise fees under the spread collection method is appropriate.

Miscellaneous Gross Receipts Taxes

277. The miscellaneous gross receipts tax is imposed on each utility company's taxable gross receipts derived from business done in an incorporated city with a population over 1,000.

278. Miscellaneous gross receipts taxes are caused by taxable receipts from business done within incorporated municipalities. The cost of miscellaneous gross receipts taxes should be directly allocated to customer classes based on inside-city revenues.

279. Collection of miscellaneous gross receipts taxes under the spread collection method is appropriate.

Primary Distribution Substation and Line Services

280. Primary distribution substation customers take service at the substation bus and do not use SWEPCO's distribution lines.

281. Primary distribution substation demands associated with the customers taking such service should be removed from the allocation factors related to the distribution investments that should not be allocated to primary distribution substation customers.

Appropriate Load Factor for Use in Average Component of A&E/4CP

282. SWEPCO proposed the use of the Texas retail load factor in its A&E/4CP methodology for allocating capacity-related production costs.

283. Because SWEPCO's generation is built to meet system needs based on analysis of the system loads, it is reasonable to allocate costs using the system load factor. The appropriate load factor for use in the A&E/4CP methodology is the system load factor.

284. The system load factor is calculated based on the annual energy use and four coincident peaks.

285. SWEPCO's system load factor during the test year was 58%.

286. DELETED.

Revenue Distribution

287. SWEPCO's proposed revenue distribution is reasonable because having few customers can make the class cost-of-service results for a particular class susceptible to unusual circumstances in a particular test year.

288. Grouping rate classes together may mitigate unusual pricing circumstances.

289. SWEPCO's proposed revenue distribution incorporates the major class groupings that were acceptable to parties to SWEPCO's last rate case settlement.

290. SWEPCO's proposed major class groupings isolate any rate class subsidies to affect rate classes within the major class groupings.

Class Cost Allocation and Rate Design
Residential

291. SWEPCO's residential service is composed of two elements: a customer charge and a consumption-based energy charge. SWEPCO has an on-peak energy charge imposed in the months of May through October (summer) for all kWh. SWEPCO has a two-tiered off peak energy charge during the months of November through April (winter) that includes a declining block rate for usage in excess of 600 kWh, in which the price of each unit is reduced after a defined level of usage.

292. It is reasonable to increase the Residential customer charge to $8.00.

293. A slight increase in the customer charge considers SWEPCO's concern that the current customer charge under-recovers the customer costs shown in the class cost-of-service study, while at the same time giving consideration to the concern that an excessive customer charge can promote wasteful energy consumption.

294. SWEPCO's Residential declining block rate structure is contrary to energy efficiency efforts and the Legislature's goal of reducing both demand and energy consumption, as stated in PURA § 39.905.

295. SWEPCO's Residential declining block rate differential should be decreased by 20% from the current level of 1.23 cents/kWh to 0.98 cents/kWh.

296. The 20% decrease addresses SWEPCO's concern of not implementing any substantial structural changes while at the same time reducing the block differential sufficiently to move towards the policy of encouraging energy efficiency.

297. It is not reasonable to create additional structure changes such as adding an inclining block to on-peak rates, because the current rate structures have only been in place for just over two years.

Commercial

298. Staff's recommended separate energy charge for the General Service (GS) class of commercial customers listed without demand meters that are billed under rate codes 208 and 218 is unnecessary because all GS customers under any GS rate code are billed consistently based on the GS rate schedule.

299. All GS customers having demand exceeding ten kilowatts (kW) are billed a demand charge for the demand in excess of 10 kW. The customers labeled as rate codes 208 and 218 do not avoid demand charges. They do not have demand exceeding ten kilowatts and are therefore treated as all GS customers are treated under the GS rate schedule.

300. Staff's recommendation to set a separate demand and energy charge for the LP primary and LP transmission class of customers and a separate customer charge for each LP subclass should not be adopted because the introduction of rate structure changes in this case result in differing percent changes to customers within the LP class, which should be avoided at this time because of the recommended revenue requirement increase.

Industrial

301. TIEC's recommended revamping of the Large Lighting and Power (LLP) rate structures by introducing an explicit customer charge and recovering any increase in revenue requirement for the industrial class in the demand charge exclusively should not be adopted at this time because even small changes in rate structure, coupled with the addition of two generating plants in rate base, can result in large swings to customer billing.

302. Offering the proposed Metal Melting Service secondary rate schedule allows the customer to make an economic decision to pay more based on its own operational

conditions to consume during the on-peak window hours as currently defined by the Electric Furnace Service rate schedule, is reasonable, and should be approved.

303. SWEPCO's proposal to increase non-firm rates by the same percentage as firm rates is reasonable because there is no basis for increasing the differential between firm and non-firm rates by holding the non-firm rates at their current levels given the interrelationship between firm and non-firm rates.

304. It is reasonable for SWEPCO to remove the loads of the primary substation-defined customers from the distribution line class cost-of-service study since those customers do not use those facilities.

305. Any study of time-of-use type rate options must include customer acceptance of rate structures because such options require more expensive metering and significantly more staff to support and because experience has shown that if customers cannot or will not use them they are simply not practical.

Dolet Hills Lignite Company Benchmark

306. Dolet Hills Lignite Company is a subsidiary of SWEPCO.

307. In *Application of SWEPCO for Reconciliation of Fuel Costs*, Docket No. 28045, Order (Apr. 20, 2004), consistent with the terms of a stipulation, the Commission ordered SWEPCO to defer for ratemaking purposes the Texas retail portion of SWEPCO's Dolet Hills Mining Venture litigation costs and reasonable actual Dolet Hills Lignite Company fuel or fuel-related costs incurred over and above the Dolet Hills Mining Venture benchmark price.

308. In Docket No. 28045, the Commission further ordered that the Dolet Hills Mining Venture benchmark price is 98% of the actual 2001 Dolet Hills Mining Venture price escalated each year thereafter based on changes in the published Gross Domestic Product-Implicit Price Deflator index.

309. In Docket No. 28045, the Commission further ordered that under specific circumstances, including termination of the stipulation in April 2011, this deferral rate treatment would terminate and SWEPCO shall absorb any remaining deferred balance.

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PUC DOCKET NO. 39896
SOAH DOCKET NO. 473-12-2979

APPLICATION OF ENTERGY TEXAS, INC. FOR AUTHORITY TO CHANGE RATES, RECONCILE FUEL COSTS, AND OBTAIN DEFERRED ACCOUNTING TREATMENT	§ § § § §	PUBLIC UTILITY COMMISSION OF TEXAS

ORDER ON REHEARING

This Order addresses the application of Entergy Texas, Inc. for authority to change rates, reconcile fuel costs, and defer costs for the transition to the Midwest Independent System Operator (MISO). In its application, Entergy requested approval of an increase in annual base-rate revenues of approximately $111.8 million (later lowered to $104.8 million), proposed tariff schedules, including new riders to recover costs related to purchased-power capacity and renewable-energy credit requirements, requested final reconciliation of its fuel costs, and requested waivers to the rate-filing package requirements.

On July 6, 2012, the State Office of Administrative Hearings (SOAH) administrative law judges (ALJs) issued a proposal for decision in which they recommended an overall rate increase for Entergy of $28.3 million resulting in a total revenue requirement of approximately $781 million. The ALJs also recommended approving total fuel costs of approximately $1.3 billion. The ALJs did not recommend approving the renewable-energy credit rider and the Commission earlier removed the purchased-power capacity rider as an issue to be addressed in this docket.[1] On August 8, 2012, the ALJs filed corrections to the proposal for decision based on the exceptions and replies of the parties.[2] Except as discussed in this Order, the Commission adopts the proposal for decision, as corrected, including findings of fact and conclusions of law.

Parties filed motions for rehearing on September 25 and October 4, 2012 and filed replies to the motions for rehearing on October 15, 2012. The Commission considered the motions for

[1] Supplemental Preliminary Order at 2, 3 (Jan. 19, 2012).

[2] Letter from SOAH judges to PUC (Aug. 8, 2012).

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rehearing at the October 25, 2012 open meeting. The Commission granted Commission Staff's motion for rehearing that requested technical corrections to reflect the rates that resulted from the Commission Staff number-running memo that was filed on August 28, 2012. The Commission modifies findings of fact 205, 206, 208, and 210 as requested by Commission Staff and attaches Commission schedules I through V to reflects its decisions. The Commission granted the Department of Energy's motion for rehearing requesting that finding of fact 198 be modified to reflect the applicable off-season for the schedulable intermittent pumping service. Finding of fact 198 is modified to reflect that the off-season is October through May. In its motion for rehearing, Entergy noted that findings of fact 17B and 17D should be modified to more accurately reflect the procedural history. The Commission modifies findings of fact 17B and 17D to state that Entergy agreed to extend time to provide the Commission sufficient time to consider the issues in this proceeding on two occasions—at the July 27 and August 30, 2012 open meetings.

I. Discussion

A. Prepaid Pension Asset Balance

Entergy included in rate base an approximately $56 million item named Unfunded Pension.[3] This amount represents the accumulated difference between the annual pension costs calculated in accordance with the Statement of Financial Accounting Standards (SFAS) No. 87 and the actual contributions made by Entergy to the pension fund—Entergy contributed nearly $56 million more to its pension fund than the minimum required by SFAS No. 87.[4]

In Docket No. 33309, the Commission allowed a pension prepayment asset, excluding the portion of the asset that is capitalized to construction work in progress (CWIP), less accrued deferred federal income taxes (ADFIT) to be included in rate base.[5] For the excluded portion, the Commission allowed the accrual of an allowance for funds used during construction

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[3] Proposal for Decision at 23 (July 6, 2012) (PFD).

[4] PFD at 23-24.

[5] *Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 33309, Order on Rehearing (March 4, 2008).

(AFUDC).[6] The ALJs concluded that this approach was sound and should be followed in this case.[7] Thus, the ALJs recommended that the CWIP-related portion of Entergy's prepaid pension asset ($25,311,236) should be excluded from the asset and should accrue AFUDC.[8] However, the ALJs did not address ADFIT.

The Commission agrees that the CWIP-related portion of Entergy's pension asset should be excluded from the asset and that this excluded portion should accrue AFUDC. However, the Commission also finds that the impact of this exclusion on Entergy's ADFIT should be reflected. When items are excluded from rate base, the related ADFIT should also be excluded. The adjusted ADFIT for the prepaid pension asset remaining in Entergy's rate base should be reduced by $8,858,933, the deferred taxes related to the excluded $25 million. The Commission adds new finding of fact 28A to reflect this modification to Entergy's ADFIT.

B. FIN 48

The Financial Accounting Standards Board's Interpretation No. 48 (FIN 48) prescribes the way in which a company must analyze, quantify, and disclose the potential consequences of tax positions that the company has taken that are legally uncertain. Entergy reported that its uncertain tax positions totaled $5,916,461. FIN 48 requires that this amount be recorded on Entergy's balance sheet as a tax liability. Entergy also reported that it made a cash deposit with the IRS in the amount of $1,294,683 associated with its FIN 48 liability.[9]

The ALJs concluded that Entergy's FIN 48 liability should be included in its ADFIT balance, but the amount of the cash deposit made by Entergy to the IRS attributable to Entergy's FIN 48 liability should not be included in Entergy's ADFIT balance. Accordingly, the ALJs recommended that $4,621,778 (Entergy's FIN 48 liability of $5,916,461 less the $1,294,683 cash deposit Entergy has already made with the IRS) be added to Entergy's ADFIT balance and thus

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[6] *Remand of Docket No. 33309 (Application of AEP Texas Central Company for Authority to Change Rates)*, Docket No. 38772, Order on Remand (Jan. 20, 2011).

[7] PFD at 26.

[8] *Id.* at 24-26.

[9] PFD at 26-27 (citing Rebuttal Testimony of Roberts, Entergy Ex. 64 at 6), 29 (citing Rebuttal Testimony of Roberts, Entergy Ex. 64 at 8).

be used to offset Entergy's rate base.[10] The ALJs did not recommend the addition of a deferred-tax-account rider because no party expressly advocated the addition of such a rider.[11]

The Commission adopts the proposal for decision regarding the adjustment to Entergy's ADFIT for the amount attributable to Entergy's FIN 48 liability. However, the Commission also follows its precedent regarding the creation of a deferred-tax-account tracker and modifies the proposal for decision on this point. In CenterPoint's Electric Delivery Company's last rate case, Docket No. 38339,[12] the Commission found that tax schedule UTP—on which companies must describe, list, and rank each uncertain tax position—would provide the IRS auditors sufficient information to quickly determine which uncertain tax positions are of a magnitude worth investigating and that an IRS audit would be more likely to occur on some uncertain tax positions. If an IRS audit of a FIN 48 uncertain tax position results in an unfavorable outcome, the utility would not be able to earn a return on the amount paid to the IRS until the next rate case.

Accordingly, the Commission authorizes Entergy to establish a rider to track unfavorable FIN-48 rulings by the IRS. The rider will also allow Entergy to recover on a *prospective* basis an after-tax return of 8.27% on the amounts paid to the IRS that result from an unfavorable FIN-48 unfavorable-tax-position audit. The return will be applied prospectively to FIN-48 amounts disallowed by an IRS audit after such amounts are actually paid to the federal government. If Entergy subsequently prevails in an appeal of an unfavorable FIN-48 unfavorable-tax-position decision by the IRS, then any amounts collected under rider related to that overturned decision shall be credited back to ratepayers.

The Commission adds new finding of fact 40A and deletes finding of fact 41 consistent with its decision to authorize the deferred-tax-account tracker.

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[10] PFD at 29.

[11] *Id.* at 29.

[12] *Application of CenterPoint Electric Delivery Company, LLC for Authority to Change Rates*, Docket No. 38339, Order on Rehearing at 3-4 (June 23, 2011).

C. Capitalized Incentive Compensation

Entergy capitalized into plant-in-service accounts some of the incentive payments made to employees and sought to include those amounts in rate base. The ALJs determined that Entergy should not be able to recover its financially based incentive-compensation costs.[13] Therefore, the portion of Entergy's incentive-compensation costs capitalized during the period July 1, 2009 through June 30, 2010 that were financially based was excluded from Entergy's rate base. The ALJs also determined that the actual percentages should be used to determine the amount that is financially based.[14]

In discussing Entergy's incentive compensation as a component of operating expenses, the ALJs adopted the method advocated by Texas Industrial Energy Consumers (TIEC) for calculating the amount of the financially based incentive costs. This method uses the actual percentage reductions applicable to each of the annual incentive programs that included a component of financially-based costs.[15]

In its exceptions regarding capitalized incentive compensation, Entergy advocated for the use of TIEC's methodology to also calculate the amount of capitalized incentive compensation that is financially based. Entergy also noted that the amount of the disallowance reflected in the schedules, $1,333,352, was calculated using a disallowance factor that included incentive compensation tied to cost-control measures, which the ALJs found to be recoverable in the operating-cost incentive-compensation calculation.[16] When the TIEC methodology is applied to the capitalized incentive-compensation costs in rate base, the net result under TIEC's methodology is that only $335,752.96 should be disallowed from capital costs.[17]

The Commission agrees that capitalized incentive compensation that is financially based should be excluded from rate base and that the exclusion only applies to incentive costs that Entergy capitalized during the period from July 1, 2009 through June 30, 2010. However, the Commission finds that a consistent methodology should be used to calculate the amount to be

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[13] PFD at 171.

[14] *Id.* at 72.

[15] *Id.* at 174; *see also* Entergy's Exceptions to the Proposal for Decision at 25-26 (July 23, 2012).

[16] Entergy's Exceptions to the Proposal for Decision at 25-26.

[17] *Id.* at 25-26.

excluded and therefore that TIEC's methodology should also be used for calculating the amount of capitalized financially based incentive-compensation costs that should be excluded from rate base. Accordingly, the total amount of capitalized incentive-compensation costs that should be disallowed from rate base is $335,752.96. Finding of fact 61 is modified to reflect this determination.

As noted by Commission Staff, this disallowance to plant-in-service alters the expense for ad valorem taxes. Accounting for this disallowance, the appropriate expense amount for ad valorem taxes is $24,921,022,[18] an adjustment of $1,222,106 to Entergy's test year amount. Finding of fact 151 is modified to reflect this adjustment to property taxes.

D. Rate of Return and Cost of Capital

The ALJs found the proper range of an acceptable return on equity for Entergy would be from 9.3 percent to 10.0 percent.[19] The mid-point of the range is 9.65 percent. The ALJs found that the effect of unsettled economic conditions facing utilities on the appropriate return on equity should be taken into account and that the effect would be to move the ultimate return on equity towards the upper limits of the range that was determined to be reasonable.[20] The ALJs found that the reasonable adjustment would be 15 basis points, moving the reasonable return on equity to 9.80 percent.[21]

The Commission must establish a reasonable return for a utility and must consider applicable factors.[22] The Commission disagrees with the ALJs that a utility's return on equity should be determined using an adder to reflect unsettled economic conditions facing utilities. The Commission agrees with the ALJs, however, that a return on equity of 9.80 percent will allow Entergy a reasonable opportunity to earn a reasonable return on its invested capital, but finds this rate appropriate independent of the 15-point adder recommended by the ALJs. A return on equity of 9.80 percent is within the range of an acceptable return on equity found by

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[18] Commission Number-Run Memorandum at 2 (Aug. 28, 2012).

[19] PFD at 94.

[20] *Id.*

[21] *Id.* at 94.

[22] PURA §§ 36.051, .052.

the ALJs. Accordingly, the Commission adds new finding of fact 65A to reflect the Commission's decision on this point.

E. Purchased-Power Capacity Expense

The ALJs rejected Entergy's request to recover $31 million more in purchased-power capacity costs than its actual test-year expenses because Entergy had failed to prove that the adjustment was known and measurable,[23] and because the request violated the matching principle.[24] Consequently, the ALJs recommended that Entergy's test-year expenses of $245,432,884 be used to set rates in this docket.[25]

Entergy pointed to an additional $533,002 of purchased-power capacity expenses that were properly included in Entergy's rate-filing package, but not provided for in the proposal for decision.[26] The Commission finds that an additional $533,002 ($6,132 for test-year expenses for Southwest Power Pool fees, $654,082 for Toledo Bend hydro fixed-charges, and -$127,212 for an Entergy intra-system billing adjustment that were all recorded in FERC account 555) of purchased-power capacity costs were incurred during the test-year and should be added to the purchased-power capacity costs in Entergy's revenue requirement. The Commission modifies findings of fact 72 and 86 to reflect the inclusion of the additional $533,002 of test-year purchased-power capacity costs, increasing the total amount to $245,965,886.

F. Labor Costs – Incentive Compensation

The ALJs found that $6,196,037, representing Entergy's financially-based incentives paid in the test-year, should be removed from Entergy's O&M expenses.[27] The ALJs agreed with Commission Staff and Cities that an additional reduction should be made to account for the FICA taxes that Entergy would have paid for those costs,[28] but did not include this reduction in a finding of fact.

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[23] PFD at 108-09.

[24] *Id.* at 109.

[25] *Id.*

[26] Entergy's Exceptions to the Proposal for Decision at 51.

[27] PFD at 175.

[28] *Id.* at 175-76.

The Commission agrees with the ALJs, but modifies finding of fact 133 to specifically include the decision that an additional reduction should be made to account for the FICA taxes Entergy would have paid on the disallowed financially-based incentive compensation. The Commission notes that this reduction for FICA taxes is reflected in the schedules attached to this Order.[29]

G. Affiliate Transactions

OPUC argued that Entergy's sales and marketing expenses exclusively benefit the larger commercial and industrial customers, but the majority of the sales, marketing, and customer service expenses are allocated to the operating companies based on customer counts. Therefore, the majority of these expenses are allocated to residential and small business customers. OPUC argued that it is inappropriate for residential and small business customers to pay for these expenses.[30] The ALJs did not adopt OPUC's position on this issue.

The Commission agrees with OPUC and reverses the proposal for decision regarding allocation of Entergy's sales and marketing expense and finds that $2.086 million of sales and marketing expense should be reallocated using direct assignment. The Commission has previously expressed its preference for direct assignment of affiliate expenses.[31] The Commission finds that the following amounts should be allocated based on a total-number-of-customers basis: (1) $46,490 for Project E10PCR56224 – Sales and Marketing – EGSI Texas; (2) $17,013 for Project F3PCD10049 – Regulated Retail Systems O&M; and (3) $30,167 for Project F3PPMMALI2 – Middle Market Mkt. Development. The remainder, $1,992,475, should be assigned to (1) General Service, (2) Large General Service and (3) Large Industrial Power Service.[32] The reallocation has the effect of increasing the revenue requirement allocated to the large business class customers and reduces the revenue requirement for small business and residential customers. New finding of fact 164A is added to reflect the proper allocation of these affiliate transactions.

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[29] *See* Commission Number Run-Memorandum at 3 (Aug. 28, 2012).

[30] Direct Testimony of Carol Szerszen, OPUC Ex. 1 at 44-45.

[31] *Application of Central Power and Light Company for Authority to Change Rates*, Docket No. 14965, Second Order on Rehearing at 87, COL 29 (Oct. 16, 1997).

[32] Direct Testimony of Carol Szerszen, OPUC Ex. 1 at Schedule CAS-7.

H. Fuel Reconciliation

Entergy proposed to allocate costs for the fuel reconciliation to customers using a line-loss study performed in 1997. Entergy conducted a line-loss study for the year ending December 31, 2010, which falls in the middle of the two year fuel reconciliation period—July 2009 through June 2011—and therefore reflects the actual line losses experienced by the customer classes during the reconciliation period. Cities argued that the allocation of fuel costs incurred over the reconciliation period should reflect the current line-loss study performed by Entergy for this case and recommended approval on a going-forward basis. Fuel factors under P.U.C. SUBST. R. 25.237(a)(3) are temporary rates subject to revision in a reconciliation proceeding described in P.U.C. SUBST. R. 25.236. P.U.C. SUBST. R. 25.236(d)(2) defines the scope of a fuel reconciliation proceeding to include any issue related to the reasonableness of a utility's fuel expenses and whether the utility has over- or under-recovered its reasonable fuel expenses.[33] Cities calculated a $3,981,271 reduction to the Texas retail fuel expenses incurred over the reconciliation period using the current line-losses. The ALJs rejected Cities' proposed adjustment finding that the P.U.C. SUBST. R. 25.237(c)(2)(B) requires the use of Commission-approved line losses that were in effect at the time fuel costs were billed to customers in a fuel reconciliation.[34]

The Commission agrees with Cities and reverses the proposal for decision regarding which line-loss factors should be used in Entergy's fuel reconciliation. Entergy used the 2010 study line-loss calculations to calculate the demand- and energy-related allocations in its cost of service analysis supporting its requested base rates. These same currently available line-loss factors should have been utilized in Entergy's fuel reconciliation. The Commission finds that Entergy's 2010 line-loss factors should be used to calculate Entergy's fuel reconciliation over-recovery. As a result, Entergy's fuel reconciliation over-recovery should be reduced by $3,981,271. Finding of fact 246A and conclusions of law 19A and 19B are added to reflect the Commission's finding that the 2010 line-loss factors be used to reconcile Entergy's fuel costs.

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[33] Cities' Exceptions to the Proposal for Decision at 20-21 (July 23, 2012).

[34] PFD at 327-328.

I. MISO Transition Expenses

During the Commission's consideration of the proposal for decision, the parties that contested the amount of Entergy's MISO transition expenses and how the transition expenses should be accounted for reached announced on the record that they had reached an agreement on these issues.[35] Those parties agreed that the MISO transition expenses would not be deferred and that Entergy's base rates should include $1.6 million for MISO transition expense.[36] The Commission adopts the agreement of the parties and accordingly modifies finding of fact 251 and deletes finding of fact 252.

J. Purchased-Power Capacity Cost Baseline

The Commission modified the amount of purchased-power capacity expense in the test-year to be $245,965,886 (see section E above). Finding of fact 255 is modified to reflect the change to the proper test-year purchased-power capacity expense.

K. Other Issues

New findings of fact 17A, 17B, 17C, 17D, and 17 E are added to reflect procedural aspects of the case after issuance of the proposal for decision.

In addition, to reflect corrections recommended by the ALJs, findings of fact 116, 123, 192, 194, and 202 are modified; and new finding of fact 182A is added.

The Commission adopts the following findings of fact and conclusions of law:

II. Findings of Fact

Procedural History

1. Entergy Texas, Inc. (ETI or the company) is an investor-owned electric utility with a retail service area located in southeastern Texas.

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[35] Open Meeting Tr. at 138 (Aug. 17, 2012).

[36] *Id.*

2. ETI serves retail and wholesale electric customers in Texas. As of June 30, 2011, ETI served approximately 412,000 Texas retail customers. The Federal Energy Regulatory Commission (FERC) regulates ETI's wholesale electric operations.

3. On November 28, 2011, ETI filed an application requesting approval of: (1) a proposed increase in annual base rate revenues of approximately $111.8 million over adjusted test-year revenues; (2) a set of proposed tariff schedules presented in the Electric Utility Rate Filing Package for Generating Utilities (RFP) accompanying ETI's application and including new riders for recovery of costs related to purchased-power capacity and renewable energy credit requirements; (3) a request for final reconciliation of ETI's fuel and purchased-power costs for the reconciliation period from July 1, 2009 to June 30, 2011; and (4) certain waivers to the instructions in RFP Schedule V accompanying ETI's application.

4. The 12-month test-year employed in ETI's filing ended on June 30, 2011 (test-year).

5. ETI provided notice by publication for four consecutive weeks before the effective date of the proposed rate change in newspapers having general circulation in each county of ETI's Texas service territory. ETI also mailed notice of its proposed rate change to all of its customers. Additionally, ETI timely served notice of its statement of intent to change rates on all municipalities retaining original jurisdiction over its rates and services.

6. The following parties were granted intervenor status in this docket: Office of Public Utility Counsel; the cities of Anahuac, Beaumont, Bridge City, Cleveland, Conroe, Dayton, Groves, Houston, Huntsville, Montgomery, Navasota, Nederland, Oak Ridge North, Orange, Pine Forest, Rose City, Pinehurst, Port Arthur, Port Neches, Shenandoah, Silsbee, Sour Lake, Splendora, Vidor, and West Orange (Cities), the Kroger Co. (Kroger); State Agencies; Texas Industrial Energy Consumers; East Texas Electric Cooperative, Inc.; the United States Department of Energy (DOE); and Wal-Mart Stores Texas, LLC, and Sam's East, Inc. (Wal-Mart). The Staff (Staff) of the Public Utility Commission of Texas (Commission or PUC) was also a participant in this docket.

7. On November 29, 2011, the Commission referred this case to the State Office of Administrative Hearings (SOAH).

8. On December 7, 2011, the Commission issued its order requesting briefing on threshold legal/policy issues.

9. On December 19, 2011, the Commission issued its Preliminary Order, identifying 31 issues to be addressed in this proceeding.

10. On December 20, 2011, the Administrative Law Judges (ALJs) issued SOAH Order No. 2, which approved an agreement among the parties to establish a June 30, 2012 effective date for the company's new rates resulting from this case pursuant to certain agreed language and consolidate *Application of Entergy Texas, Inc. for Authority to Defer Expenses Related to its Proposed Transition to Membership in the Midwest Independent System Operator*, Docket No. 39741 (pending) into this proceeding. Although it did not agree, Staff did not oppose the consolidation.

11. On January 13, 2012, the ALJs issued SOAH Order No. 4 granting the motions for admission pro hac vice filed by Kurt J. Boehm and Jody M. Kyler to appear and participate as counsel for Kroger and the motion for admission *pro hac vice* filed by Rick D. Chamberlain to appear and participate as counsel for Wal-Mart.

12. On January 19, 2012, the Commission issued a supplemental preliminary order identifying two additional issues to be addressed in this case and concluding that the company's proposed purchased-power capacity rider should not be addressed in this case and that such costs should be recovered through base rates.

13. ETI timely filed with the Commission petitions for review of the rate ordinances of the municipalities exercising original jurisdiction within its service territory. All such appeals were consolidated for determination in this proceeding.

14. On April 4, 2012, the ALJs issued SOAH Order No. 13 severing rate case expense issues into *Application of Entergy Texas, Inc. for Rate Case Expenses Severed from PUC Docket No. 39896*, Docket No. 40295 (pending).

15. On April 13, 2012, ETI adjusted its request for a proposed increase in annual base rate revenues to approximately $104.8 million over adjusted test-year revenues.

16. The hearing on the merits commenced on April 24 and concluded on May 4, 2012.

17. Initial post-hearing briefs were filed on May 18 and reply briefs were filed on May 30, 2012.

17A. On August 7, 2012, the SOAH ALJs filed a letter with the Commission recommending changes to the PFD.

17B At the July 27, 2012 open meeting, ETI agreed to extend time to August 31, 2012 to provide the Commission sufficient time to consider the issues in this proceeding.

17C. The Commission considered the proposal for decision at the August 17, 2012 and August 30, 2012 open meetings.

17D. At the August 30, 2012 open meeting, ETI agreed to extend time to September 14, 2012 to provide the Commission sufficient time to consider the issues in this proceeding.

17E. At the August 17, 2012 open meeting, parties announced on the record a settlement of the amount of costs for the transition to MISO.

Rate Base

18. Capital additions that were closed to ETI's plant-in-service between July 1, 2009 and June 30, 2011, are used and useful in providing service to the public and were prudently incurred.

19. ETI's proposed Hurricane Rita regulatory asset was an issue resolved by the black-box settlement in *Application of Entergy Texas, Inc. for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 37744 (Dec. 13, 2010).

20. Accrual of carrying charges on the Hurricane Rita regulatory asset should have ceased when Docket No. 37744 concluded because the asset would have then begun earning a rate of return as part of rate base.

21. The appropriate calculation of the Hurricane Rita regulatory asset should begin with the amount claimed by ETI in Docket No. 37744, less amortization accruals to the end of the test-year in the present case, and less the amount of additional insurance proceeds received by ETI after the conclusion of Docket No. 37744.

22. A Test-Year-end balance of $15,175,563 for the Hurricane Rita regulatory asset should remain in rate base, applying a five-year amortization rate beginning August 15, 2010.

23. The Hurricane Rita regulatory asset should not be moved to the storm damage insurance reserve.

24. The company requested in rate base its prepaid pension assets balance of $55,973,545, which represents the accumulated difference between the Statement of Financial Accounting Standards (SFAS) No. 87 calculated pension costs each year and the actual contributions made by the company to the pension fund.

25. The prepaid pension assets balance includes $25,311,236 capitalized to construction work in progress (CWIP).

26. It is not necessary to the financial integrity of ETI to include CWIP in rate base, and there was insufficient evidence showing that major projects under construction were efficiently and prudently managed.

27. The portion of the prepaid pension assets balance that is capitalized to CWIP should not be included in ETI's rate base.

28. The remainder of the prepaid pension assets balance should be included in ETI's rate base.

28A. When items are excluded from rate base, the related ADFIT should also be excluded. The amount of ADFIT associated with the $25 million capitalized to CWIP and excluded from rate base is $8,858,933. The adjusted ADFIT for the prepaid pension asset remaining in Entergy's rate base should be reduced by $8,858,933.

29. ETI should be permitted to accrue an allowance for funds used during construction on the portion of ETI's Prepaid Pension Assets Balance capitalized to CWIP.

30. The Financial Accounting Standard Board (FASB) Financial Interpretation No. 48 (FIN 48), "Accounting for Uncertainty in Income Taxes," requires ETI to identify each of its uncertain tax positions by evaluating the tax position on its technical merits to determine whether the position, and the corresponding deduction, is more-likely-than-not to be sustained by the Internal Revenue Service (IRS) if audited.

31. FIN 48 requires ETI to remove the amount of its uncertain tax positions from its Accumulated Deferred Federal Income Tax (ADFIT) balance for financial reporting

purposes and record it as a potential liability with interest to better reflect the company's financial condition.

32. At test-year-end, ETI had $5,916,461 in FIN 48 liabilities, meaning ETI has, thus far, avoided paying to the IRS $5,916,461 in tax dollars (the FIN 48 liability) in reliance upon tax positions that the company believes will not prevail in the event the positions are challenged, via an audit, by the IRS.

33. ETI has deposited $1,294,683 with the IRS in connection with the FIN 48 liability.

34. The IRS may never audit ETI as to its uncertain tax positions creating the FIN 48 liability.

35. Even if ETI is audited, ETI might prevail on its uncertain tax positions.

36. ETI may never have to pay the IRS the FIN 48 liability.

37. Other than the amount of its deposit with the IRS, ETI has current use of the FIN 48 liability funds.

38. Until actually paid to the IRS, the FIN 48 liability represents cost-free capital and should be deducted from rate base.

39. The amount of $4,621,778 (representing ETI's full FIN 48 liability of $5,916,461 less the $1,294,683 cash deposit ETI has made with the IRS for the FIN 48 liability) should be added to ETI's ADFIT and thus be used to reduce ETI's rate base.

40. ETI's application and proposed tariffs do not include a request for a tracking mechanism or rider to collect a return on the FIN 48 liability.

40A. It is appropriate for ETI to create a deferred-tax-account tracker in the form of a rider to recover on a prospective basis an after–tax return of 8.27% on the amounts paid to the IRS that result from an unfavorable FIN 48 audit. The rider will track unfavorable FIN 48 rulings and the return will be applied prospectively to FIN 48 amounts disallowed by an IRS audit after such amounts are actually paid to the federal government. If ETI prevails in an appeal of a FIN 48 decision, then any amounts collected under the rider related to that decision should be credited back to ratepayers.

41. Deleted.

42. Investor-owned electric utilities may include a reasonable allowance for cash working capital in rate base as determined by a lead-lag study conducted in accordance with the Commission's rules.

43. Cash working capital represents the amount of working capital, not specifically addressed in other rate base items, that is necessary to fund the gap between the time expenditures are made and the time corresponding revenues are received.

44. The lead-lag study conducted by ETI considered the actual operations of ETI, adjusted for known and measurable changes, and is consistent with P.U.C. SUBST. R. 25.231(c)(2)(B)(iii).

45. It is reasonable to establish ETI's cash working capital requirement based on ETI's lead-lag study as updated in Jay Joyce's rebuttal testimony and on the cost of service approved for ETI in this case.

46. As a result of the black-box settlements in *Application of Entergy Gulf States, Inc. for Authority to Change Rates and to Reconcile Fuel Costs*, Docket No. 34800 (Nov. 7, 2008) and Docket No. 37744, the Commission did not approve ETI's storm damage expenses since 1996 and its storm damage reserve balance.

47. ETI established a prima facie case concerning the prudence of its storm damage expenses incurred since 1996.

48. Adjustments to the storm damage reserve balance proposed by intervenors should be denied.

49. The Hurricane Rita regulatory asset should not be moved to the storm damage insurance reserve.

50. ETI's appropriate Test-Year-end storm reserve balance was negative $59,799,744.

51. The amount of $9,846,037, representing the value of the average coal inventory maintained at ETI's coal-burning facilities, is reasonable, necessary, and should be included in rate base.

52. The Spindletop gas storage facility (Spindletop facility) is used and useful in providing reliable and flexible natural gas supplies to ETI's Sabine Station and Lewis Creek generating plants.

53. The Spindletop facility is critical to the economic, reliable operation of the Sabine Station and Lewis Creek generating plants due to their geographic location in the far western region of the Entergy system.

54. It is reasonable and appropriate to include ETI's share of the costs to operate the Spindletop facility in rate base.

55. Staff recommended updating ETI's balance amounts for short-term assets to the 13-month period ending December 2011, which was the most recent information available. Staff's proposed adjustments should be incorporated into the calculation of ETI's rate base.

56. The following short-term asset amounts should be included in rate base: prepayments at \$8,134,351; materials and supplies at \$29,285,421; and fuel inventory at \$52,693,485.

57. The amount of \$1,127,778, representing costs incurred by ETI when it acquired the Spindletop facility, represent actual costs incurred to process and close the acquisition, not mere mark-up costs.

58. ETI's \$1,127,778 in capitalized acquisition costs should be included in rate base because ETI incurred these costs in conjunction with the purchase of a viable asset that benefits its retail customers.

59. In its application, ETI capitalized into plant in service accounts some of the incentive payments ETI made to its employees. ETI seeks to include those amounts in rate base.

60. A portion of those capitalized incentive accounts represent payments made by ETI for incentive compensation tied to financial goals.

61. The portion of ETI's incentive payments that are capitalized and that are financially-based should be excluded from ETI's rate base because the benefits of such payments inure most immediately and predominantly to ETI's shareholders, rather than its electric

customers. ETI's capitalized incentive compensation that is financially based is $335,752.96 and should be removed for rate base.

62. The test-year for ETI's prior ratemaking proceeding ended on June 30, 2009, and the reasonableness of ETI's capital costs (including capitalized incentive compensation) for that prior period was dealt with by the Commission in that proceeding and is not at issue in this proceeding.

63. In this proceeding, ETI's capitalized incentive compensation that is financially-based should be excluded from rate base, but only for incentive costs that ETI capitalized during the period from July 1, 2009 (the end of the prior test-year) through June 30, 2010 (the commencement of the current test-year).

Rate of Return and Cost of Capital

64. A return on common equity (ROE) of 9.80 percent will allow ETI a reasonable opportunity to earn a reasonable return on its invested capital.

65. The results of the discounted cash flow model and risk premium approach support a ROE of 9.80 percent.

65A. It is not appropriate to add 15 points to the ROE due to unsettled economic conditions facing utilities.

66. A 9.80 percent ROE is consistent with ETI's business and regulatory risk.

67. ETI's proposed 6.74 percent embedded cost of debt is reasonable.

68. The appropriate capital structure for ETI is 50.08 percent long-term debt and 49.92 percent common equity.

69. A capital structure composed of 50.08 percent debt and 49.92 percent equity is reasonable in light of ETI's business and regulatory risks.

70. A capital structure composed of 50.08 percent debt and 49.92 percent equity will help ETI attract capital from investors.

71. ETI's overall rate of return should be set as follows:

COMPONENT	CAPITAL STRUCTURE	COST OF CAPITAL	WEIGHTED AVG COST OF CAPITAL
LONG-TERM DEBT	50.08%	6.74%	3.38%
COMMON EQUITY	49.92%	9.80%	4.89%
TOTAL	100.00%		8.27%

Operating Expenses

72. ETI's test-year purchased capacity expenses were $245,965,886.

73. ETI requested an upward adjustment of $30,809,355 as a post-test-year adjustment to its purchased capacity costs. This request was based on ETI's projections of its purchased capacity expenses during a period beginning June 1, 2012 and ending May 31, 2013 (the rate-year).

74. ETI's purchased capacity expense projections were based on estimates of rate-year expenses for: (a) reserve equalization payments under Schedule MSS-1; (b) payments under third-party capacity contracts; and (c) payments under affiliate contracts.

75. ETI's projection of its rate-year reserve equalization payments under Schedule MSS-1 is based on numerous assumptions, including load growths for ETI and its affiliates, future capacity contracts for ETI and its affiliates, and future values of the generation assets of ETI and its affiliates.

76. There is substantial uncertainty with regard to ETI's projection of its rate-year reserve equalization payments under Schedule MSS-1.

77. ETI's projection of its rate-year third-party capacity contract payments includes numerous assumptions, one of which is that every single third-party supplier will perform at the maximum level under the contract, even though that assumption is inconsistent with ETI's historical experience.

78. There is substantial uncertainty with regard to ETI's projection of its rate-year third-party capacity-contract payments.

79. ETI's estimates of its rate-year purchases under affiliate contracts are based on a mathematical formula set out in Schedule MSS-4.

80. The MSS-4 formula for rate-year affiliate capacity payments reflects that these payments will be based on ratios and costs that cannot be determined until the month that the payments are to be made.

81. Over $11 million of ETI's affiliate transactions were based on a 2013 contract (the EAI WBL Contract) that was not signed until April 11, 2012.

82. There is uncertainty about whether the EAI WBL Contract will ever go into effect.

83. ETI projects purchasing over 300 megawatts (MW) more in purchased capacity in the rate-year than it purchased in the test-year.

84. ETI experienced substantial load growth in the two years before the test-year, and it continues to project similar load growth in the future.

85. ETI did not meet its burden of proof to demonstrate that a known and measurable adjustment of $30,809,355 should be made to its test-year purchased capacity expenses.

86. ETI's purchased capacity expense in this case should be based on the test-year level of $245,965,886.

87. ETI incurred $1,753,797 of transmission equalization expense during the test-year.

88. ETI proposed an upward adjustment of $8,942,785 for its transmission equalization expense. This request was based on ETI's projections of its transmission equalization expenses during the rate-year.

89. The transmission equalization expense that ETI will pay in the rate-year will depend on future costs and loads for each of the Entergy operating companies.

90. ETI's projection of its rate-year transmission equalization expenses is uncertain and speculative because it depends on a number of variables, including future transmission investments, deferred taxes, depreciation reserves, costs of capital, tax rates, operating expenses, and loads of each of the Entergy operating companies.

91. ETI seeks increased transmission equalization expenses for transmission projects that are not currently used and useful in providing electric service. ETI's post-test-year adjustment is based on the assumption that certain planned transmission projects will go

into service after the test-year. At the close of the hearing, none of the planned transmission projects had been fully completed and some were still in the planning phase.

92. It is not reasonable for ETI to charge its retail ratepayers for transmission equalization expenses related to projects that are not yet in-service.

93. ETI's request for a post-test-year adjustment of $8,942,785 for rate-year transmission equalization expenses should be denied because those expenses are not known and measurable. ETI's post-test-year adjustment does not with reasonable certainty reflect what ETI's transmission equalization expense will be when rates are in effect.

94. ETI's transmission equalization expense in this case should be based on the test-year level of $1,753,797.

95. P.U.C. SUBST. R. 25.231(c)(2)(ii) states that the reserve for depreciation is the accumulation of recognized allocations of original cost, representing the recovery of initial investment over the estimated useful life of the asset.

96. Except in the case of the amortization of the general plant deficiency, the use of the remaining life depreciation method to recover differences between theoretical and actual depreciation reserves is the most appropriate method and should be continued.

97. It is reasonable for ETI to calculate depreciation reserve allocations on a straight-line basis over the remaining, expected useful life of the item or facility.

98. Except as described below, the service lives and net salvage rates proposed by the company are reasonable, and these service lives and net salvage rates should be used in calculating depreciation rates for the company's production, transmission, distribution, and general plant assets.

99. A 60-year life for Sabine Units 4 and 5 is reasonable for purposes of establishing production plant depreciation rates.

100. The retirement (actuarial) rate method, rather than the interim retirement method, should be used in the development of production plant depreciation rates.

101. Production plant net salvage is reasonably based on the negative five percent net salvage in existing rates.

102. The net salvage rate of negative 10 percent for ETI's transmission structures and improvements (FERC Account 352) is the most reasonable of those proposed and should be adopted.

103. The net salvage rate of negative 20 percent for ETI's transmission station equipment (FERC Account 353) is the most reasonable of those proposed and should be adopted.

104. The net salvage rate of negative five percent for ETI's transmission towers and fixtures (FERC Account 354) is the most reasonable of those proposed and should be adopted.

105. The net salvage rate of negative 30 percent for ETI's transmission poles and fixtures (FERC Account 355) is the most reasonable of those proposed and should be adopted.

106. The net salvage rate of negative 30 percent for ETI's transmission overhead conductors and devices (FERC Account 356) is the most reasonable of those proposed and should be adopted.

107. A service life of 65 years and a dispersion curve of R3 for ETI's distribution structures and improvements (FERC Account 361) are the most reasonable of those proposed and should be approved.

108. A service life of 40 years and a dispersion curve of R1 for ETI's distribution poles, towers, and fixtures (FERC Account 364) are the most reasonable of those proposed and should be approved.

109. A service life of 39 years and a dispersion curve of R0.5 for ETI's distribution overhead conductors and devices (FERC Account 365) are the most reasonable of those proposed and should be approved.

110. A service life of 35 years and a dispersion curve of R1.5 for ETI's distribution underground conductors and devices (FERC Account 367) are the most reasonable of those proposed and should be approved.

111. A service life of 33 years and a dispersion curve of L0.5 for ETI's distribution line transformers (FERC Account 368) are the most reasonable of those proposed and should be approved.

112. A service life of 26 years and a dispersion curve of L4 for ETI's distribution overhead service (FERC Account 369.1) are the most reasonable of those proposed and should be approved.

113. The net salvage rate of negative five percent for ETI's distribution structures and improvements (FERC Account 361) is the most reasonable of those proposed and should be adopted.

114. The net salvage rate of negative 10 percent for ETI's distribution station equipment (FERC Account 362) is the most reasonable of those proposed and should be adopted.

115. The net salvage rate of negative seven percent for ETI's distribution overhead conductors and devices (FERC Account 365) is the most reasonable of those proposed and should be adopted.

116. The net salvage rate of positive five percent for ETI's distribution line transformers (FERC Account 368) is the most reasonable of those proposed and should be adopted.

117. The net salvage rate of negative 10 percent for ETI's distribution overhead services (FERC Account 369.1) is the most reasonable of those proposed and should be adopted.

118. The net salvage rate of negative 10 percent for ETI's distribution underground services (FERC Account 369.2) is the most reasonable of those proposed and should be adopted.

119. A service life of 45 years and a dispersion curve of R2 for ETI's general structures and improvements (FERC Account 390) are the most reasonable of those proposed and should be approved.

120. The net salvage rate of negative 10 percent for ETI's general structures and improvements (FERC Account 390) is the most reasonable of those proposed and should be adopted.

121. It is reasonable to convert the $21.3 million deficit that has developed over time in the reserve for general plant accounts to General Plant Amortization.

122. A ten-year amortization of the deficit in the reserve for general plant accounts is reasonable and should be adopted.

123. FERC pronouncement AR-15 requires amortization over the same life as recommended based on standard life analysis. A standard life analysis determined that a five-year life was appropriate for general plant computer equipment (FERC Account 391.2). Therefore, a five year amortization for this account is reasonable and should be adopted.

124. ETI proposed adjustments to its test-year payroll costs to reflect: (a) changes to employee headcount levels at ETI and Entergy Services, Inc. (ESI); and (b) approved wage increases set to go into effect after the end of the test-year.

125. The proposed payroll adjustments are reasonable but should be updated to reflect the most recent available information on headcount levels as proposed by Commission Staff. In addition to adjusting payroll expense levels, the more recent headcount numbers should be used to adjust the level of payroll tax expense, benefits expense, and savings plan expense.

126. Staff has appropriately updated headcount levels to the most recent available data but errors made by Staff should be corrected. The corrections related to: (a) a double counting of three ETI and one ESI employee; (b) inadvertent use of the ETI benefits cost percentage in the calculation of ESI benefits costs; (c) an inappropriate reduction of savings plan costs when such costs were already included in the benefits percentage adjustments; and (d) corrections for full-time equivalents calculations. Staff's ETI headcount adjustment (AG-7) overstated operation and maintenance (O&M) payroll reduction by $224,217, and ESI headcount adjustment (AG-7) understated O&M payroll increase by $37,531.

127. ETI included $14,187,744 for incentive compensation expenses in its cost of service.

128. The compensation packages that ETI offers its employees include a base payroll amount, annual incentive programs, and long-term incentive programs. The majority of the compensation is for operational measures, but some is for financial measures.

129. Incentive compensation that is based on financial measures is of more immediate and predominant benefit to shareholders, whereas incentive compensation based on operational measures is of more immediate and predominant benefit to ratepayers.

130. Incentives to achieve operational measures are necessary and reasonable to provide utility services but those to achieve financial measures are not.

131. The $5,376,975 that was paid for long term incentive programs was tied to financial measures and, therefore, should not be included in ETI's cost of service.

132. Of the amounts that were paid pursuant to the Executive Annual Incentive Plan, $819,062 was tied to financial measures and, therefore, should be disallowed.

133. In total, the amount of incentive compensation that should be disallowed is $6,196,037 because it was related to financial measures that are not reasonable and necessary for the provision of electric service. An additional reduction should be made to account for the FICA taxes ETI would have paid on the disallowed financially based incentive compensation.

134. The amount of incentive compensation that should be included in the cost of service is $7,991,707.

135. To attract and retain highly qualified employees, the Entergy companies provide a total package of compensation and benefits that is equivalent in scope and cost with what other comparable companies within the utility business and other industries provide for their employees.

136. When using a benchmark analysis to compare companies' levels of compensation, it is reasonable to view the market level of compensation as a range rather than a precise, single point.

137. ETI's base pay levels are at market.

138. ETI's benefits plan levels are within a reasonable range of market levels.

139. ETI's level of compensation and benefits expense is reasonable and necessary.

140. ETI provides non-qualified supplemental executive retirement plans for highly compensated individuals such as key managerial employees and executives that, because of limitations imposed under the Internal Revenue Code, would otherwise not receive retirement benefits on their annual compensation over $245,000 per year.

141. ETI's non-qualified supplemental executive retirement plans are discretionary costs designed to attract, retain, and reward highly compensated employees whose interests are more closely aligned with those of the shareholders than the customers.

142. ETI's non-qualified executive retirement benefits in the amount of $2,114,931 are not reasonable or necessary to provide utility service to the public, not in the public interest, and should not be included in ETI's cost of service.

143. For the employee market in which ETI operates, most peer companies offer moving assistance. Such assistance is expected by employees, and ETI would be placed at a competitive disadvantage if it did not offer relocation expenses.

144. ETI's relocation expenses were reasonable and necessary.

145. The company's requested operating expenses should be reduced by $40,620 to reflect the removal of certain executive prerequisites proposed by Staff.

146. Staff properly adjusted the company's requested interest expense of $68,985 by removing $25,938 from FERC account 431 (using the interest rate of 0.12 percent for calendar year 2012), leaving a recommended interest expense of $43,047.

147. During the test-year, ETI's property tax expense equaled $23,708,829.

148. ETI requested an upward *pro forma* adjustment of $2,592,420, to account for the property tax expenses ETI estimates it will pay in the rate-year.

149. ETI's requested *pro forma* adjustment is not reasonable because it is based, in part, upon the prediction that ETI's property tax rate will be increased in 2012, a change that is speculative is not known and measurable.

150. Staff's recommendation to increase ETI's test-year property tax expenses by $1,214,688 is based on the historical effective tax rate applied to the known test-year-end plant in service value, consistent with Commission precedent, and based upon known and measurable changes.

151. ETI's test-year property tax burden should be adjusted upward by $1,222,106 for a total expense of $24,921,022.

152. Staff recommended reducing ETI's advertising, dues, and contributions expenses by $12,800. The recommendation, which no party contested, should be adopted.

153. The final cost of service should reflect changes to cost of service that affect other components of the revenue requirement such as the calculation of the Texas state gross receipts tax, the local gross receipts tax, the PUC Assessment Tax and the Uncollectible Expenses.

154. The company's requested Federal income tax expense is reasonable and necessary.

155. ETI's request for $2,019,000 to be included in its cost of service to account for the company's annual decommissioning expenses associated with River Bend is not reasonable because it is not based upon "the most current information reasonably available regarding the cost of decommissioning" as required by P.U.C. SUBST. R. 25.231(b)(1)(F)(i).

156. Based on the most current information reasonably available, the appropriate level of decommissioning costs to be included in ETI's cost of service is $1,126,000.

157. ETI's appropriate total annual self-insurance storm damage reserve expense is $8,270,000, comprised of an annual accrual of $4,400,000 to provide for average annual expected storm losses, plus an annual accrual of $3,870,000 for 20 years to restore the reserve from its current deficit.

158. ETI's appropriate target self-insurance storm damage reserve is $17,595,000.

159. ETI should continue recording its annual storm damage reserve accrual until modified by a Commission order.

160. The operating costs of the Spindletop facility are reasonable and necessary.

161. The operating costs of the Spindletop facility paid to PB Energy Storage Services are eligible fuel expenses.

Affiliate Transactions

162. ETI affiliates charged ETI $78,998,777 for services during the test-year. The majority of these O&M expenses—$69,098,041—were charged to ETI by ESI. The remaining affiliate services were charged (or credited) to ETI by: Entergy Gulf States Louisiana,

L.L.C.; Entergy Arkansas, Inc.; Entergy Louisiana, LLC; Entergy Mississippi, Inc.; Entergy Operations, Inc.; and non-regulated affiliates.

163. ESI follows a number of processes to ensure that affiliate charges are reasonable and necessary and that ETI and its affiliates are charged the same rate for similar services. These processes include: (a) the use of service agreements to define the level of service required and the cost of those services; (b) direct billing of affiliate expenses where possible; (c) reasonable allocation methodologies for costs that cannot be directly billed; (d) budgeting processes and controls to provide budgeted costs that are reasonable and necessary to ensure appropriate levels of service to its customers; and (e) oversight controls by ETI's Affiliate Accounting and Allocations Department.

164. Affiliates charged expenses to ETI through 1292 project codes during the test-year.

164A. The $2,086,145 in affiliate transactions related to sales and marketing expenses should be reallocated using direct assignment. The following amounts should be allocated to all retail classes in proportion to number of customers: (1) $46,490 for Project E10PCR56224 – Sales and Marketing – EGSI Texas; (2) $17,013 for Project F3PCD10049 – Regulated Retail Systems O&M; and (3) $30,167 for Project F3PPMMALI2 – Middle Market Mkt. Development. The remainder, $1,992,475, should be assigned to (1) General Service, (2) Large General Service and (3) Large Industrial Power Service.

165. ETI agreed to remove the following affiliate transactions from its application: (1) Project F3PPCASHCT (Contractual Alternative/Cashpo) in the amount of $2,553; (2) Project F3PCSPETEI (Entergy-Tulane Energy Institute) in the amount of $14,288; and (3) Project F5PPKATRPT (Storm Cost Processing & Review) in the amount of $929.

166. The $356,151 (which figure includes the $112,531 agreed to by ETI) of costs associated with Projects F5PCZUBENQ (Non-Qualified Post Retirement) and F5PPZNQBDU (Non Qual Pension/Benf Dom Utl) are costs that are not reasonable and necessary for the provision of electric utility service and are not in the public interest.

167. The $10,279 of costs associated with Project F3PPFXERSP (Evaluated Receipts Settlement) are not normally-recurring costs and should not be recoverable.

168. The $19,714 of costs associated with Project F3PPEASTIN (Willard Eastin et al) are related to ESI's operations, it is more immediately related to Entergy Louisiana, Inc. and Entergy New Orleans, Inc. As such, they are not recoverable from Texas ratepayers.

169. The $171,032 of costs associated with Project F3PPE9981S (Integrated Energy Management for ESI) are research and development costs related to energy efficiency programs. As such, they should be recovered through the energy efficiency cost recovery factor rather than base rates.

170. Except as noted in the above findings of fact Nos. 162-169, all remaining affiliate transactions were reasonable and necessary, were allowable, were charged to ETI at a price no higher than was charged by the supplying affiliate to other affiliates, and the rate charged is a reasonable approximation of the cost of providing service.

Jurisdictional Cost Allocation

171. ETI has one full or partial requirements wholesale customer – East Texas Electric Cooperative, Inc.

172. ETI proposes that 150 MW be set as the wholesale load for developing retail rates in this docket. Using 150 MW to set the wholesale load is reasonable. The 150 MW used to set the wholesale load results in a retail production demand allocation factor of 95.3838 percent.

173. The 12 Coincident Peak (12 CP) allocation method is consistent with the approach used by the FERC to allocate between jurisdictions.

174. Using 12CP methodology to allocate production costs between the wholesale and retail jurisdictions is the best method to reflect cost responsibility and is appropriate based on ETI's reliance on capacity purchases.

Class Cost Allocation and Rate Design

175. There is no express statutory authorization for ETI's proposed Renewable Energy Credits rider (REC rider).

176. REC rider constitutes improper piecemeal ratemaking and should be rejected.

177. ETI's test-year expense for renewable energy credits, $623,303, is reasonable and necessary and should be included in base rates.

178. Municipal Franchise Fees (MFF) is a rental expense paid by utilities for the right to use public rights-of-way to locate its facilities within municipal limits.

179. ETI is an integrated utility system. ETI's facilities located within municipal limits benefit all customers, whether the customers are located inside or outside of the municipal limits.

180. Because all customers benefit from ETI's rental of municipal right-of-way, municipal franchise fees should be charged to all customers in ETI's service area, regardless of geographic location.

181. It is reasonable and consistent with the Public Utility Regulatory Act (PURA) § 33.008(b) that MFF be allocated to each customer class on the basis of in-city kilowatt hour (kWh) sales, without an adjustment for the MFF rate in the municipality in which a given kWh sale occurred.

182. The same reasons for allocating and collecting MFF as set out in Finding of Fact Nos. 178-181 also apply to the allocation and collection of Miscellaneous Gross Receipts Taxes. The company's proposed allocation of these costs to all retail customer classes based on customer class revenues relative to total revenues is appropriate.

182A. ETI's proposed gross plant-based allocator is an appropriate method for allocating the Texas franchise tax.

183. The Average and Excess (A&E) 4CP method for allocating capacity-related production costs, including reserve equalization payments, to the retail classes is a standard methodology and the most reasonable methodology.

184. The A&E 4CP method for allocating transmission costs to the retail classes is standard and the most reasonable methodology.

185. ETI appropriately followed the rate class revenue requirements from its cost of service study to allocate costs among customer classes. ETI's revenue allocation properly sets rates at each class's cost of service.

186. It is reasonable for ETI to eliminate the service condition for Rate Groups A and C in Schedule SHL [Street and Highway Lighting Service] that charges a $50 fee for any replacement of a functioning light with a lower-wattage bulb.

187. It is appropriate to require ETI to prepare and file, as part of its next base rate case, a study regarding the feasibility of instituting LED-based rates and, if the study shows that such rates are feasible, ETI should file proposals for LED-based lighting and traffic signal rates in its next rate case.

188. An agreement was reached by the parties and approved by the Commission in Docket No. 37744 that directed ETI to exclude, in its next rate case, the life-of-contract demand ratchet for existing customers in the Large Industrial Power Service (LIPS), Large Industrial Power Service-Time of Day, General Service, General Service-Time of Day, Large General Service, and Large General Service-Time of Day rate schedules.

189. ETI's proposed tariffs in this case did not remove the life-of-contract demand ratchet from these rate schedules consistent with the parties' agreement in Docket No. 37744.

190. A perpetual billing obligation based on a life-of-contract demand ratchet, as ETI proposed, is not reasonable.

191. ETI's proposed LIPS and LIPS Time of Day tariffs should be modified to reflect the agreement that was adopted by the Commission as just and reasonable in Docket No. 37744. Accordingly, these tariffs should be modified as set out in Findings of Fact No. 192-194.

192. ETI's Schedule LIPS and LIPS Time of Day § VI should be changed to read:

> DETERMINATION OF BILLING LOAD
>
> The kW of Billing Load will be the greatest of the following:
>
> (A) The Customer's maximum measured 30-minute demand during any 30-minute interval of the current billing month, subject to §§ III, IV and V above; or
>
> (B) 75% of Contract Power as defined in § VII; or
>
> (C) 2,500 kW.

193. ETI's Schedule LIPS and LIPS Time of Day § VII should be changed to read:

> DETERMINATION OF CONTRACT POWER
>
> Unless Company gives customer written notice to the contrary, Contract Power will be defined as below:
>
> Contract Power - the highest load established under § VI(A) above during the 12 months ending with the current month. For the initial 12 months of Customer's service under the currently effective contract, the Contract Power shall be the kW specified in the currently effective contract unless exceeded in any month during the initial 12-month period.

194. The Large General Service, Large General Service-Time of Day, General Service, and General Service-Time of Day schedules should be similarly revised to eliminate ETI's life-of-contract demand ratchet.

195. In its proposed rate design for the LIPS class, the company took a conservative approach and increased the current rates by an equal percentage. This minimized customer bill impacts while maintaining cost causation principles on a rate class basis.

196. It is a reasonable move towards cost of service to add a customer charge of $630 to the LIPS rate schedule with subsequent increases to be considered in subsequent base rate cases.

197. It is a reasonable move towards cost of service to slightly decrease the LIPS energy charges and increase the demand charges as proposed by Staff witness William B. Abbott.

198. DOE proposed a new Schedule LIPS rider—Schedule "Schedulable Intermittent Pumping Service" (SIPS) for load schedulable at least four weeks in advance, that occurs in the off-season (October through May), that can be cancelled at any time, and for load not lasting more than 80 hours in a year. For customers whose loads match these SIPS characteristics (for example, DOE's Strategic Petroleum Reserve), the 12-month demand ratchet provision of Schedule LIPS does not apply to demands set under the provisions of the SIPS rider. The monthly demand set under the SIPS provisions would be applicable for billing purposes only in the month in which it occurred. In short, if a customer set a

12-month ratchet demand in that month, it would be forgiven and not applicable in the succeeding 12 months.

199. DOE's proposed Schedule SIPS is not restricted solely to the DOE and should be adopted. It more closely addresses specific customer characteristics and provides for cost-based rates, as does another ETI rider applicable to Pipeline Pumping Service.

200. Standby Maintenance Service (SMS) is available to customers who have their own generation equipment and who contract for this service from ETI.

201. P.U.C. SUBST. R. 25.242(k)(1) provides that rates for sales of standby and maintenance power to qualifying facilities should recognize system wide costing principles and should not be discriminatory.

202. It is reasonable to move Schedule SMS toward cost of service by: (a) adding a customer charge equivalent to that of the LIPS rate schedule only for SMS customers not purchasing supplementary power under another applicable rate; and (b) revising the tariff as follows:

Charge	Distribution (less than 69KV)	Transmission (69KV and greater)
Billing Load Charge ($/kW):		
Standby	$2.46	$0.79
Maintenance	$2.27	$0.60
Non-Fuel Energy Charge (¢/kWh)		
On-Peak	4.245¢	4.074¢
Off-Peak	0.575¢	0.552¢

203. ETI's Additional Facilities Charge rider (Schedule AFC) prescribes the monthly rental charge paid by a customer when ETI installs facilities for that customer that would not normally be supplied, such as line extensions, transformers, or dual feeds.

204. ETI existing Schedule AFC provides two pricing options. Option A is a monthly charge. Option B, which applies when a customer elects to amortize the directly-assigned facilities over a shorter term ranging from one to ten years, has a variable monthly charge. There is also a term charge that applies after the facility has been fully depreciated.

205. It is reasonable and cost-based to reduce the Schedule AFC Option A rate to 1.11 percent per month of the installed cost of all facilities included in the agreement for additional facilities.

206. It is reasonable and cost-based to reduce the Schedule AFC Option B monthly rate and the Post Term Recovery Charge as follows:

Selected Recovery Term	Recovery Term Charge	Post Recovery Term Charge
1	9.52%	0.28%
2	5.14%	0.28%
3	3.68%	0.28%
4	2.95%	0.28%
5	2.52%	0.28%
6	2.23%	0.28%
7	2.03%	0.28%
8	1.88%	0.28%
9	1.76%	0.28%
10	1.67%	0.28%

207. The revisions in the above findings of fact to Schedule AFC rates reasonably reflect the costs of running, operating, and maintaining the directly-assigned facilities.

208. It is reasonable to modify the Large General Service rate schedule by increasing the demand charge from $8.56 to $11.43; decreasing the energy charge from $.00854 to $.00458; and reducing the customer charge to $260.00.

209. Staff's proposed change to the General Service (GS) rate schedule to gradually move GS customers towards their cost of service by recommending a decrease in the customer charge from the current rate of $41.09 to $39.91, and a decrease in the energy charges is reasonable and should be adopted.

210. ETI's Residential Service (RS) rate schedule is composed of two elements: a customer charge and a consumption-based energy charge. In the months November through April (winter), the rates are structured as a declining block, in which the price of each unit is reduced after a defined level of usage. ETI's proposed increase in the RS customer charge to $6 per month is reasonable and should be adopted. For the RS summer rate and

the first winter block rate, the 6.296¢ per kWh energy charge resulting from the increased revenue requirement for residential customers is reasonable and should be adopted.

211. ETI's Schedule RS declining block rate structure is contrary to energy-efficiency efforts and the Legislature's goal of reducing both energy demand and energy consumption in Texas, as stated in PURA § 39.905.

212. Schedule RS winter block rates should be modified consistent with the goal set out in PURA § 39.905, with the initial phase-in of a 20 percent reduction in the block differential proposed by ETI and subsequent reductions should be reviewed for consideration at the occurrence of each rate case filing.

213. Other elements of Schedule RS are just and reasonable.

Fuel Reconciliation

214. ETI incurred $616,248,686 in natural-gas expenses during the reconciliation period, which is from July 2009 through June 2011.

215. ETI purchased natural gas in the monthly and daily markets and pursuant to a long-term contract with Enbridge Inc. pipeline. ETI also transported gas on its own account and negotiated operational balancing agreements with various pipeline companies.

216. ETI employed a diversified portfolio of gas supply and transportation agreements to meet its natural-gas requirements, and ETI prudently managed its gas-supply contracts.

217. ETI's natural gas expenses were reasonable and necessary expenses incurred to provide reliable electric service to retail customers.

218. ETI incurred $90,821,317 in coal expenses during the reconciliation period.

219. ETI prudently managed its coal and coal-related contracts during the reconciliation period.

220. ETI monitored and audited coal invoices from Louisiana Generating, LLC for coal burned at the Big Cajun II, Unit 3 facility.

221. ETI's coal expenses were reasonable and necessary expenses incurred to provide reliable electric service to retail customers.

222. ETI incurred $990,041,434 in purchased-energy expenses during the reconciliation period.

223. The Entergy System's planning and procurement processes for purchased-power produced a reasonable mix of purchased resources at a reasonable price.

224. During the reconciliation period, ETI took advantage of opportunities in the fuel and purchased-power markets to reduce costs and to mitigate against price volatility.

225. ETI's purchased-energy expenses were reasonable and necessary expenses incurred to provide reliable electric service to retail customers.

226. ETI provided sufficient contemporaneous documentation to support the reasonableness of its purchased-power planning and procurement processes and its actual power purchases during the reconciliation period.

227. The Entergy system sold power off system when the revenues were expected to be more than the incremental cost of supplying generation for the sale, subject to maintaining adequate reserves.

228. The System Agreement is the tariff approved by the FERC that provides the basis for the operation and planning of the Entergy system, including the six operating companies. The System Agreement governs the wholesale-power transactions among the operating companies by providing for joint operation and establishing the bases for equalization among the operating companies, including the costs associated with the construction, ownership, and operation of the Entergy system facilities.

229. Under the terms of the Entergy System Agreement, ETI was allocated its share of revenues and expenses from off-system sales.

230. During the reconciliation period, ETI recorded off-system sales revenue in the amount of $376,671,969 in FERC Account 447 and credited 100 percent of off-system sales revenues and margins from off-system sales to eligible fuel expenses.

231. ETI properly recorded revenues from off-system sales and credited those revenues to eligible fuel costs.

232. The Entergy system consists of six operating companies, including ETI, which are planned and operated as a single, integrated electric system under the terms of the System Agreement.

233. Service schedule MSS-1 of the System Agreement determines how the capability and ownership costs of reserves for the Entergy system are equalized among the operating companies. These inter-system "reserve equalization" payments are the result of a formula rate related to the Entergy system's reserve capability that is applied on a monthly basis.

234. Reserve capability under service schedule MSS-1 is capability in excess of the Entergy system's actual or planned load built or acquired to ensure the reliable, efficient operation of the electric system.

235. By approving service schedule MSS-1, the FERC has approved the method by which the operating companies share the cost of maintaining sufficient reserves to provide reliability for the Entergy system as a whole.

236. Service schedule MSS-3 of the System Agreement determines the pricing and exchange of energy among the operating companies. By approving service schedule MSS-3, the FERC has approved the method by which the operating companies are reimbursed for energy sold to the exchange energy pool and how that energy is purchased.

237. Service schedule MSS-4 of the System Agreement sets forth the method for determining the payment for unit power purchases between operating companies. By approving service schedule MSS-4, the FERC has approved the methodology for pricing inter-operating company unit power purchases.

238. The Entergy system is planned using multi-year, annual, seasonal, monthly, and next-day horizons. Once the planning process has identified the most economical resources that can be used to reliably meet the aggregate Entergy system demand, the next step is to procure the fuel necessary to operate the generating units as planned and acquire wholesale power from the market.

239. Once resources are procured to meet forecasted load, the Entergy system is operated during the current day using all the resources available to meet the total Entergy system demand.

240. After current-day operation, the System Agreement prescribes an accounting protocol to bill the costs of operating the system to the individual operating companies. This protocol is implemented via the intra-system bill to each operating company on a monthly basis.

241. ETI purchased power from affiliated operating companies per the terms of service schedule MSS-3 of the System Agreement. The payments made under Schedule MSS-3 to affiliated operating companies are reasonable and necessary, and the FERC has approved the pricing formula and the obligation to purchase the energy. ETI pays the same price per megawatt hour for energy under service schedule MSS-3 as does any other operating company purchasing energy under service schedule MSS-3 during the same hour.

242. The Spindletop facility is used primarily to ensure gas-supply reliability and guard against gas-supply curtailments that can occur as a result of extreme weather or other unusual events.

243. The Spindletop facility provides a secondary benefit of flexibility in gas supply. ETI can back down gas-fired generation to take advantage of more economical wholesale power, or use gas from storage to supplement gas-fired generation when load increases during the day and thereby avoid more expensive intra-day gas purchases.

244. ETI's customers received benefits from the Spindletop facility during the reconciliation period through reliable gas supplies and ETI's monthly and daily storage activity.

245. ETI prudently managed the Spindletop facility to provide reliability and flexibility of gas supply for the benefit of customers.

246. ETI proposed new loss factors, based on a December 2010 line-loss study, to be applied for the purpose of allocating its costs to its wholesale customers and retail customer classes.

246A. ETI's 2010 line-loss factors should be used to reconcile ETI's fuel costs. Therefore, ETI's fuel reconciliation over-recovery should be reduced by $3,981,271.

247. ETI's proposed loss factors are reasonable and shall be implemented on a prospective basis as a result of this final order.

248. ETI seeks a special-circumstances exception to recover $99,715 resulting from the FERC's reallocation of rough production equalization costs in FERC Order No. 720-A, and to treat such costs as eligible fuel expense.

249. Special circumstances exist and it is appropriate for ETI to recover the rough production cost equalization costs reallocated to ETI as a result of the FERC's decision in Order No. 720-A.

<u>Other Issues</u>

250. A deferred accounting of ETI's Midwest Independent Transmission System Operator (MISO) transition expenses is not necessary to carry out any requirement of PURA.

251. ETI should include $1.6 million in base rates for MISO transition expense.

252. Deleted.

253. Transmission Cost Recovery Factor baseline values should be set during the compliance phase of this docket, after the Commission makes final rulings on the various contested issues that may affect this calculation.

254. Distribution Cost Recovery Factor baseline values should be set during the compliance phase of this docket, after the Commission makes final rulings on the various contested issues that may affect this calculation.

255. The appropriate amount for ETI's purchased-power capacity expense to be included in base rates is $245,965,886.

256. The amount of ETI's purchased-power capacity expense includes third-party contracts, legacy affiliate contracts, other affiliate contracts, and reserve equalization. Whether the amounts for all contracts should be included in the baseline for a purchased-capacity rider that may be approved in Project No. 39246 is an issue that should be decided in that project.

III. Conclusions of Law

1. ETI is a "public utility" as that term is defined in PURA § 11.004(1) and an "electric utility" as that term is defined in PURA § 31.002(6).

2. The Commission exercises regulatory authority over ETI and jurisdiction over the subject matter of this application pursuant to PURA §§ 14.001, 32.001, 32.101, 33.002, 33.051, 36.101–.111, and 36.203.

3. SOAH has jurisdiction over matters related to the conduct of the hearing and the preparation of a proposal for decision in this docket, pursuant to PURA § 14.053 and TEX. GOV'T CODE ANN. § 2003.049.

4. This docket was processed in accordance with the requirements of PURA and the Texas Administrative Procedure Act, Tex. Gov't Code Ann. Chapter 2001.

5. ETI provided notice of its application in compliance with PURA § 36.103, P.U.C. PROC. R. 22.51(a), and P.U.C. SUBST. R. 25.235(b)(1)-(3).

6. Pursuant to PURA § 33.001, each municipality in ETI's service area that has not ceded jurisdiction to the Commission has jurisdiction over the company's application, which seeks to change rates for distribution services within each municipality.

7. Pursuant to PURA § 33.051, the Commission has jurisdiction over an appeal from a municipality's rate proceeding.

8. ETI has the burden of proving that the rate change it is requesting is just and reasonable pursuant to PURA § 36.006.

9. In compliance with PURA § 36.051, ETI's overall revenues approved in this proceeding permit ETI a reasonable opportunity to earn a reasonable return on its invested capital used and useful in providing service to the public in excess of its reasonable and necessary operating expenses.

10. Consistent with PURA § 36.053, the rates approved in this proceeding are based on original cost, less depreciation, of property used and useful to ETI in providing service.

11. The ADFIT adjustments approved in this proceeding are consistent with PURA § 36.059 and P.U.C. SUBST. R. 25.231(c)(2)(C)(i).

12. Including the cash working capital approved in this proceeding in ETI's rate base is consistent with P.U.C. SUBST. R. 25.231(c)(2)(B)(iii)(IV), which allows a reasonable allowance for cash working capital to be included in rate base.

13. The ROE and overall rate of return authorized in this proceeding are consistent with the requirements of PURA §§ 36.051 and 36.052.

14. The affiliate expenses approved in this proceeding and included in ETI's rates meet the affiliate payment standards articulated in PURA §§ 36.051, 36.058, and *Railroad Commission of Texas v. Rio Grande Valley Gas Co.*, 683 S.W.2d 783 (Tex. App.—Austin 1984, no writ).

15. The ADFIT adjustments approved in this proceeding are consistent with PURA § 36.059 and P.U.C. SUBST. R. 25.231(c)(2)(C)(i).

16. Pursuant to P.U.C. SUBST. R. 25.231(b)(1)(F), the decommissioning expense approved in this case is based on the most current information reasonably available regarding the cost of decommissioning, the balance of funds in the decommissioning trust, anticipated escalation rates, the anticipated return on the funds in the decommissioning trust, and other relevant factors.

17. ETI has demonstrated that its eligible fuel expenses during the reconciliation period were reasonable and necessary expenses incurred to provide reliable electric service to retail customers as required by P.U.C. SUBST. R. 25.236(d)(1)(A). ETI has properly accounted for the amount of fuel-related revenues collected pursuant to the fuel factor during the reconciliation period as required by P.U.C. SUBST. R. 25.236(d)(1)(C).

18. ETI prudently managed the dispatch, operations, and maintenance of its fossil plants during the reconciliation period.

19. The reconciliation period level operating and maintenance expenses for the Spindletop facility are eligible fuel expenses pursuant to P.U.C. SUBST. R. 25.236(a).

19A. Fuel factors under P.U.C. SUBST. R. 25.237(a)(3) are temporary rates subject to revision in a reconciliation proceeding.

19B. P.U.C. SUBST. R. 25.236(d)(2) defines the scope of a fuel reconciliation proceeding to include any issue related to the reasonableness of a utility's fuel expenses and whether the utility has over- or under-recovered its reasonable fuel expenses. It is proper to use the new line-loss study to calculate Entergy's fuel reconciliation and over-recovery.

20. Special circumstances are warranted pursuant to P.U.C. SUBST. R. 25.236(a)(6) to recover rough production equalization payments reallocated to ETI by the FERC.

21. ETI's rates, as approved in this proceeding, are just and reasonable in accordance with PURA § 36.003.

IV. Ordering Paragraphs

In accordance with these findings of fact and conclusions of law, the Commission issues the following orders:

1. The proposal for decision prepared by the SOAH ALJs is adopted to the extent consistent with this Order.

2. ETI's application is granted to the extent consistent with this Order.

3. ETI shall file in Tariff Control No. 40742 *Compliance Tariff Pursuant to Final Order in Docket No. 39896 (Application of Entergy Texas, Inc. for Authority to Change Rates, Reconcile Fuel Costs, and Obtain Deferred Accounting Treatment)* tariffs consistent with this Order within 20 days of the date of this Order. No later than ten days after the date of the tariff filings, Staff shall file its comments recommending approval, modification, or rejection of the individual sheets of the tariff proposal. Responses to the Staff's recommendation shall be filed no later than 15 days after the filing of the tariff. The Commission shall by letter approve, modify, or reject each tariff sheet, effective the date of the letter.

4. The tariff sheets shall be deemed approved and shall become effective on the expiration of 20 days from the date of filing, in the absence of written notification of modification or rejection by the Commission. If any sheets are modified or rejected, ETI shall file proposed revisions of those sheets in accordance with the Commission's letter within ten

days of the date of that letter, and the review procedure set out above shall apply to the revised sheets.

5. Copies of all tariff-related filings shall be served on all parties of record.

6. ETI shall prepare and file as part of its next base rate case a study regarding the feasibility of instituting LED-based rates and, if the study shows that such rates are feasible, ETI should file proposals for LED-based lighting and traffic signal rates in that case. If ETI has LED lighting customers taking service, the study shall include detailed information regarding differences in the cost of serving LED and non-LED lighting customers. ETI shall provide the results of this study to Cities and interested parties as soon as practicable, but no later than the filing of its next rate case.

7. All other motions, requests for entry of specific findings of fact and conclusions of law, and any other requests for general or specific relief, if not expressly granted, are denied.

SIGNED AT AUSTIN, TEXAS the 1st day of ~~October~~ November 2012.

PUBLIC UTILITY COMMISSION OF TEXAS

DONNA L. NELSON, CHAIRMAN

ROLANDO PABLOS, COMMISSIONER

I respectfully dissent regarding the utility- and executive-management-class affiliate transactions. To be consistent with Commission precedent in Docket No. 14965,[37] the indirect costs of the management of Entergy's ultimate parent should not be borne by Texas ratepayers. Therefore, I would disallow the following: $173,867 for Project No. F3PCCPM001 (Corporate Performance Management); $372,919 for Project No. F3PCC31255 (Operations-Office of the CEO); and $74,485 for Project No. F3PPCOO001 (Chief Operating Officer). I join the Commission in all other respects for this Order.

KENNETH W. ANDERSON, JR., COMMISSIONER

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[37] *Application of Central Power and Light Company for Authority to Change Rates*, Docket No. 14965, Second Order on Rehearing (Oct. 16, 1997).

SOAH DOCKET NO.	473-12-2979
PUC DOCKET NO.	39896
COMPANY NAME	Entergy Texas, Inc
TEST YEAR END	30-Jun-11

COMM Schedule I
Revenue Requirement

		Test Year Total (a)	Company Adjustments To Test Year (b)	Company Requested Test Year Total Electric (c)	Commission Adjustments To Company Request (d)	Commission Adjusted Total Electric (e) = (c) + (d)
REVENUE REQUIREMENT						
Operations & Maintenance		$ 1,291,684,714	$ (1,075,148,117)	$ 216,536,597	$ (24,550,490)	$ 191,986,107
Regulatory Debits and Credits	407 00	$ (6,784,608)	$ 12,030,533	$ 5,245,925	$ (324,121)	$ 4,921,804
Accretion Expense		$ 212,783	$ (212,783)	$ -	$ -	$ -
Interest on Customer Deposits		$ -	$ 68,985	$ 68,985	$ (25,938)	$ 43,047
Decommissioning Expense		$ -	$ -	$ -	$ -	$ -
Depreciation & Amortization Expense		$ 76,072,459	$ 22,558,698	$ 98,631,157	$ (6,253,316)	$ 92,377,841
Taxes Other Than Income Taxes		$ 63,023,906	$ (2,533,159)	$ 60,490,747	$ (2,874,506)	$ 57,616,241
Federal Income Taxes		$ (23,407,031)	$ 67,296,739	$ 43,889,708	$ 6,181,384	$ 50,071,092
Current State Income Taxes		$ (127,519)	$ 89,787	$ (37,732)	$ 37,732	$ -
Deferred Federal Income Taxes		$ 67,051,463	$ (52,089,274)	$ 14,962,189	$ (14,962,189)	$ -
Deferred State Income Taxes		$ 812,265	$ (727,918)	$ 84,347	$ (84,347)	$ -
Investment Tax Credits	411.00	$ (1,611,177)	$ (46,429)	$ (1,657,606)	$ 1,657,606	$ -
Consolidated Tax Savings Adjustment		$ -	$ -	$ -	$ -	$ -
Return on Invested Capital		$ -	$ 155,162,991	$ 155,162,991	$ (14,562,393)	$ 140,600,598
TOTAL		**$ 1,466,927,255**	**$ (873,549,947)**	**$ 593,377,308**	**$ (55,760,578)**	**$ 537,616,730**

Plus:		
Addback: Purchased Power Rider	555.00	$ 244,539,884
Addback: Interruptible Services	555 00	$ -
Total Addbacks		**$ 244,539,884**

Total COMM Revenue Requirement	**$ 782,156,614**

SOAH DOCKET NO. 473-12-2979
PUC DOCKET NO. 39896
COMPANY NAME Entergy Texas, Inc.
TEST YEAR END 30-Jun-11

COMM Schedule II
O&M Expense

OPERATIONS AND MAINTENANCE EXPENSE	Acct. No	Test Year Total (a)	Company Adjustments To Test Year (b)	Company Requested Test Year Total Electric (c)	Commission Adjustments To Company Request (d)	Commissioin Adjusted Total Electric (e) = (c) + (d)
Operations & Maintenance:						
Prod. Operation and Supr	500	$ 5,338,227	$ 52,215	$ 5,390,442	$ (96,362)	$ 5,294,080
Fuel	501	$ (255,242)	$ -	$ (255,242)	$ -	$ (255,242)
Fuel-Oil	501	$ 664,745	$ (663,891)	$ 854	$ -	$ 854
Fuel-Natural Gas	501	$ 330,035,996	$ (330,035,996)	$ -	$ -	$ -
Fuel-Coal	501	$ 49,170,094	$ (46,618,748)	$ 2,551,346	$ (1,466)	$ 2,549,880
Steam Expenses	502	$ 3,900,803	$ 40,940	$ 3,941,743	$ (61,223)	$ 3,880,520
Electric Expenses	505	$ 2,529,473	$ 9,516	$ 2,538,989	$ 684	$ 2,539,673
Misc Steam Power Expenses	506	$ 8,135,921	$ 31,297	$ 8,167,218	$ (74,347)	$ 8,092,871
Rents	507	$ 131,131	$ -	$ 131,131	$ -	$ 131,131
NOX Emmissions Allowance Expense	509	$ (43,244)	$ 43,244	$ -	$ -	$ -
NOX Seasonal Allowance Expense	509	$ 11,904	$ (11,904)	$ -	$ -	$ -
Maintenance Supv and Eng	510	$ 1,166,596	$ 21,037	$ 1,187,633	$ (18,303)	$ 1,169,330
Maintenance of structures	511	$ 3,104,201	$ 4,593	$ 3,108,794	$ (6,872)	$ 3,101,922
Maintenance of boiler plant	512	$ 12,592,212	$ 21,742	$ 12,613,954	$ (17,587)	$ 12,596,367
Maintenance of electric plant	513	$ 5,491,510	$ 729,791	$ 6,221,301	$ (27,550)	$ 6,193,751
Maintenance of misc steam plant	514	$ 1,314,917	$ (18,801)	$ 1,296,116	$ (15,889)	$ 1,280,227
Hydraulic Operating Supv and Eng	535	$ (841)	$ (27)	$ (868)	$ 9	$ (859)
Misc Hydro Power Generation	539	$ (12)	$ -	$ (12)	$ -	$ (12)
Maintenance Supv and Eng	541	$ (1,359)	$ (32)	$ (1,391)	$ 14	$ (1,377)
Maintenance of electric plant	544	$ 1,303	$ 13	$ 1,316	$ (26)	$ 1,290
Maintenance of Misc hydraulic plant	545	$ 543	$ -	$ 543	$ -	$ 543
Operation Supv and Eng	546	$ (1,288)	$ (12)	$ (1,300)	$ 23	$ (1,277)
Misc. Other Power Gen Exp	549	$ (91)	$ -	$ (91)	$ -	$ (91)
Purchased Power-System Companies	555	$ 111,253,452	$ (111,253,452)	$ -	$ -	$ -
Purchased Power-from others	555	$ 159,034,737	$ (159,034,737)	$ -	$ 533,002 Comm	$ 533,002
Co-Generation	555	$ 148,658,981	$ (148,658,981)	$ -	$ -	$ -
Rsrc Plan PurPow-Affilated	555	$ 308,866,766	$ (308,866,766)	$ -	$ -	$ -
Purchased Power Entergy Affiliates	555	$ 25,558,973	$ (25,558,973)	$ -	$ -	$ -
Renewable Energy Credit	555	$ -	$ -	$ -	$ 623,303	$ 623,303
System Control & Load Dispatch	556	$ 951,691	$ 19,686	$ 971,377	$ (19,111)	$ 952,266
System Control & Dispatch Other	557	$ 321,455	$ 4,301	$ 325,756	$ (6,391)	$ 319,365
Deferred Electric Fuel Cost	557	$ (52,121,822)	$ 52,121,822	$ -	$ -	$ -
Deferred TX capacity rider	557	$ (12,448)	$ 12,448	$ -	$ -	$ -
Transmission Ops Supr & Engr	560	$ 5,568,076	$ (117,800)	$ 5,450,276	$ (31,045)	$ 5,419,231
Load Dispatching	561	$ 842,620	$ 8,987	$ 851,607	$ (79,413)	$ 772,194
Load Dispatching-reliability	561	$ 231,424	$ 5,608	$ 237,032	$ 1,191	$ 238,223
Load Dispatching-transmission system	561	$ 1,422,924	$ 31,890	$ 1,454,814	$ 6,365	$ 1,461,179
Load Dispatching-Trans Serv & Sch	561	$ 577,895	$ 12,964	$ 590,859	$ 2,886	$ 593,745
System Planning & Standards Dev	561	$ 385,684	$ 7,877	$ 393,561	$ 1,755	$ 395,316
Transmission Service Studies	561	$ 52,780	$ 1,139	$ 53,919	$ 242	$ 54,161
Transmission Station Equipment	562	$ 142,626	$ 925	$ 143,551	$ (1,813)	$ 141,738
Trans OH Line Expense	563	$ 483,385	$ 66	$ 483,451	$ (129)	$ 483,322
Transmission Equalization	565	$ 1,377,103	$ 9,319,479	$ 10,696,582	$ (8,942,785)	$ 1,753,797
Misc. Transmission Expenses	566	$ 924,736	$ (19,401)	$ 905,335	$ (11,518)	$ 893,817
Rents	567	$ 987,823	$ -	$ 987,823	$ -	$ 987,823
Maint. Supv And Eng.	568	$ 3,041,227	$ 313,096	$ 3,354,323	$ (29,859)	$ 3,324,464
Maint. Of Structures	569	$ 106,642	$ 42	$ 106,684	$ (6,215)	$ 100,469
Maint Trans Computer & Telecom	569	$ 448,842	$ 6,215	$ 455,057	$ 155	$ 455,212
Transmission Maint Station Equip	570	$ 1,692,713	$ 7,266	$ 1,699,979	$ (14,177)	$ 1,685,802
Transmission Maint OH Line Exp	571	$ 1,790,447	$ 40	$ 1,790,487	$ (79)	$ 1,790,408
Maint. Of Misc. Transmission	573	$ 52,814	$ -	$ 52,814	$ -	$ 52,814
Regional Energy Mkts-Oper Supv	575	$ 18,998	$ 4,034,420	$ 4,053,418	$ (2,452,989) Comm	$ 1,600,429
DayAhead & Real Time Mkts WPP	575	$ 37,069	$ 810	$ 37,879	$ (397)	$ 37,482
Maint of Computer Software WPP	576	$ 3,168	$ -	$ 3,168	$ -	$ 3,168
Distribution Ops Supr & Engr	580	$ 5,357,005	$ 26,983	$ 5,383,988	$ (66,797)	$ 5,317,191
Distribution Load Dispatching	581	$ 448,718	$ 4,367	$ 453,085	$ (8,488)	$ 444,597
Distribution Station Expenses	582	$ 471,978	$ 2,931	$ 474,909	$ (5,715)	$ 469,194
Distribution OH Line Expenses	583	$ 103,332	$ 771	$ 104,103	$ (1,511)	$ 102,592
Underground Line Expenses	584	$ 746,886	$ 2,638	$ 749,524	$ (5,173)	$ 744,351
Street Lighting & Signal Sys	585	$ 286,809	$ 2,296	$ 289,105	$ (4,152)	$ 284,953
Meter Expenses	586	$ 2,088,756	$ 13,593	$ 2,102,349	$ (25,176)	$ 2,077,173
Customer Installations	587	$ 470,236	$ 3,787	$ 474,023	$ (7,349)	$ 466,674
Miscellaneous Distribution Exp	588	$ 1,503,004	$ 4,505	$ 1,507,509	$ (19,425)	$ 1,488,084
Rents	589	$ 3,925,626	$ -	$ 3,925,626	$ -	$ 3,925,626
Distribution Maint Supr & Engr	590	$ 1,455,611	$ (4,009)	$ 1,451,602	$ (23,447)	$ 1,428,155
Maint. Of Structures	591	$ 180,488	$ -	$ 180,488	$ -	$ 180,488
Distribution Maint Station Equip	592	$ 860,084	$ 6,186	$ 866,270	$ (11,078)	$ 855,192
Distribution Maint OH lines	593	$ 10,544,165	$ 20,914	$ 10,565,079	$ (43,524)	$ 10,521,555
Underground Line Expenses	594	$ 802,465	$ 5,293	$ 807,758	$ (10,732)	$ 797,026
Dist Maint Line Trnf, Regulators	595	$ 15,851	$ 51	$ 15,902	$ (36)	$ 15,866
MaintStreet Light & Signal Sys	596	$ 635,209	$ 4,176	$ 639,385	$ (8,188)	$ 631,197
Maintenance-Non Roadway Sec Ltg	596	$ 392,358	$ 2,678	$ 395,036	$ (5,252)	$ 389,784
Maintenance of Meters	597	$ 159,186	$ 1,366	$ 160,552	$ (2,678)	$ 157,874
Maint of Misc Distr Plant	598	$ 449,866	$ 1,928	$ 451,794	$ (3,039)	$ 448,755
Supervision - Customer Accts	901	$ 258,934	$ 2,458	$ 261,392	$ (4,552)	$ 256,840
Meter Reading Exp	902	$ 3,843,502	$ 8,762	$ 3,852,264	$ (9,366)	$ 3,842,898
Customer Records	903	$ 5,250,761	$ 71,989	$ 5,322,750	$ (66,377)	$ 5,256,373
Customer Collection	903	$ 4,745,821	$ 38,181	$ 4,784,002	$ -	$ 4,784,002
Customer Deposit Interest	903.2	$ -	$ -	$ -	$ -	$ -
Uncollectible Accounts	904	$ 2,835,831	$ 2,051,289	$ 4,887,120	$ (459,250)	$ 4,427,870
Effective Rate		0.000000000000		0.008236108685		0.008236108685
Uncollectible Accounts-revenue adj		$ -	$ (307,648)	$ (307,648)	$ 307,648	$ -
Uncollectible Accounts Elect-Write Off	904	$ (1,106,887)	$ -	$ (1,106,887)	$ -	$ (1,106,887)
Miscellaneous	905	$ 33,149	$ 610	$ 33,759	$ (670)	$ 33,089
Factoring Expense	426.5	$ -	$ -	$ -	$ -	$ -
Factoring Factor		0.0000000000000		0.0000000000000		0.0000000000000
Supervision	907	$ 392,505	$ (2,721)	$ 389,784	$ (5,629)	$ 384,155

Customer Assistance	908	$	9,189,638	$	(7,250,909)	$	1,938,729	$	(67,298)	$	1,871,431
Customer Assistance over/under	908	$	1,747,892	$	(1,747,892)	$	-	$	-	$	-
Information & Instr Advertising	909	$	937,069	$	(876)	$	936,193	$	(4,056)	$	932,137
Misc. Cust. Service and Information	910	$	1,151,988	$	4,764	$	1,156,752	$	-	$	1,156,752
Sales Supervision	911	$	829	$	7	$	836	$	(17,467)	$	(16,631)
Demonstrating & Selling Exp	912	$	730,161	$	14,522	$	744,683	$	(16,597)	$	728,086
Advertising Expense	913	$	110,202	$	(2,379)	$	107,823	$	(58)	$	107,765
Misc. Sales Expense	916	$	256,775	$	1,715	$	258,490	$	(1,390)	$	257,100
		$	-	$	-	$	-			$	-
TOTAL Operations & Maintenance		$	1,207,264,083	$	(1,071,013,726)	$	136,250,357	$	(11,342,739)	$	124,907,618

SOAH DOCKET NO.	473-12-2979
PUC DOCKET NO.	39896
COMPANY NAME	Entergy Texas, Inc.
TEST YEAR END	30-Jun-11

COMM Schedule II
O&M Expense

OPERATIONS AND MAINTENANCE EXPENSE		Test Year Total (a)	Company Adjustments To Test Year (b)	Company Requested Test Year Total Electric (c)	Commission Adjustments To Company Request (d)	Commission Adjusted Total Electric (e) = (c) + (d)
Administrative & General:						
Admin & General Salaries	920	$ 18,405,932	$ (1,460,140)	$ 16,945,792	$ (5,773,708)	$ 11,172,084
Office Supplies & Exp	921	$ 1,590,193	$ (459,339)	$ 1,130,854	$ (5,400)	$ 1,125,454
Admin Expenses Transferred	922	$ 1,059,941	$ 1,006	$ 1,060,947	$ 214	$ 1,061,161
Outside Services	923	$ 14,921,589	$ (5,431,183)	$ 9,490,406	$ (89,762)	$ 9,400,644
Property Insurance	924	$ 1,134,432	$ 1,287	$ 1,135,719	$ -	$ 1,135,719
Provision for Property Insurance	924	$ 3,699,996	$ 5,060,004	$ 8,760,000	$ (491,172)	$ 8,268,828
Environmental Reserve Accrual	924	$ 1,153,576	$ -	$ 1,153,576	$ -	$ 1,153,576
Injuries & Damages	925	$ 1,859,658	$ 7,424	$ 1,867,082	$ (5,437)	$ 1,861,645
Employee Pensions & Benefits	926	$ 27,027,557	$ (17,961)	$ 27,009,596	$ (2,678,305)	$ 24,331,291
Regulatory Commission Exp	928	$ 7,708,335	$ (1,984,403)	$ 5,723,932	$ (4,150,717)	$ 1,573,215
General Advertising Exp	9301	$ 62,040	$ (65)	$ 61,975	$ (343)	$ 61,632
Miscellaneous	9302	$ 796,138	$ 224,312	$ 1,020,450	$ (9,181)	$ 1,011,269
Active Development Expenses	9302	$ 21	$ -	$ 21	$ -	$ 21
Directors' Fees and Expenses	9302	$ 79,476	$ (79,476)	$ -	$ -	
Rents	931	$ 3,264,425	$ 1,164	$ 3,265,589	$ -	$ 3,265,589
Maint. Of General Plant	935	$ 1,657,322	$ 2,979	$ 1,660,301	$ (3,940)	$ 1,656,361
TOTAL Administrative & General		84,420,631	(4,134,391)	80,286,240	(13,207,751)	67,078,489
TOTAL O & M EXPENSE		**1,291,684,714**	**(1,076,148,117)**	**216,536,597**	**(24,550,490)**	**$ 191,986,107**

SOAH DOCKET NO.	**473-12-2979**
PUC DOCKET NO.	**39896**
COMPANY NAME	**Entergy Texas, Inc.**
TEST YEAR END	**30-Jun-11**

COMM Schedule III
Invested Capital

	Test Year Total (a)	Company Adjustments To Test Year (b)	Company Requested Test Year Total Electric (c)	Commission Adjustments To Company Request (d)	Commission Adjusted Total Electric (e) = (c) + (d)
INVESTED CAPITAL					
Plant in Service	$ 3,521,368,187	$ (251,512,491)	$ 3,269,855,696	$ (335,753)	$ 3,269,519,943
Accumulated Depreciation	$ (1,417,946,172)	$ 148,061,290	$ (1,269,884,882)	$ -	$ (1,269,884,882)
Net Plant in Service	$ 2,103,422,015	$ (103,451,201)	$ 1,999,970,814	$ (335,753)	$ 1,999,635,061
		$ -			
Construction Work in Progress	$ -	$ -	$ -	$ -	$ -
Plant Held for Future Use	$ -	$ -	$ -	$ -	$ -
Working Cash Allowance	$ -	$ (2,013,921)	$ (2,689,275)	$ (3,697,959)	$ (6,387,234)
Fuel Inventories	$ 53,759,975	$ -	$ 53,759,975	$ (1,066,490)	$ 52,693,485
Materials and Supplies	$ 29,252,574	$ -	$ 29,252,574	$ 32,847	$ 29,285,421
Prepayments	$ 7,366,433	$ (148,396)	$ 7,218,037	$ 916,313	$ 8,134,350
Property Insurance Reserve	$ -	$ 59,799,744	$ 59,799,744	$ -	$ 59,799,744
Injuries and Damages Reserve	$ (5,569,243)	$ -	$ (5,569,243)	$ -	$ (5,569,243)
Coal Car Maintenance Reserve	$ 1,400,350	$ -	$ 1,400,350	$ -	$ 1,400,350
Unfunded Pension	$ (53,715,841)	$ 109,689,386	$ 55,973,545	$ (25,311,236)	$ 30,662,309
Allowances	$ 68,914	$ -	$ 68,914	$ -	$ 68,914
Environmental Reserves	$ 3,412,379	$ (4,474,569)	$ (1,062,190)	$ -	$ (1,062,190)
Customer Deposits	$ (35,872,476)	$ -	$ (35,872,476)	$ -	$ (35,872,476)
Regulatory Assets and Liabilities	$ -	$ 26,366,859	$ 26,366,859	$ (11,054,064)	$ 15,312,795
Accumulated DFIT	$ (824,338,691)	$ 369,967,144	$ (454,371,547)	$ 6,398,405	$ (447,973,142)
Rate Case Expenses	$ -	$ 6,175,000	$ 6,175,000	$ (6,175,000)	$ -
	$ -	$ -	$ -	$ -	$ -
TOTAL INVESTED CAPITAL (RATE BASE)	**$ 1,279,186,389**	**$ 461,910,046**	**$ 1,740,421,081**	**$ (40,292,937)**	**$ 1,700,128,144**
RATE OF RETURN	**5.140%**		**8.92%**		**8.2700%**
RETURN ON INVESTED CAPITAL	**$ -**	**$ 155,162,991**	**$ 155,162,991**	**$ (14,562,393)**	**$ 140,600,598**