Entergy

Entergy Arkansas, Inc.
Regulatory Affairs
425 West Capitol Avenue
P. O. Box 551
Little Rock, AR 72203-0551
Tel 501 377 4000

RECEIVED

JUN 20 2007

TN REGULATORY AUTHORITY
UTILITIES DIVISION

June 18, 2006

Mr. Lewis DeBoard
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, TN 37243-0505

Re: In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service
TRA Docket No. 06-00216

Dear Mr. DeBoard:

In follow-up to earlier conversations regarding Entergy Arkansas, Inc.'s (EAI) pending retail rate filing before the Arkansas Public Service Commission (APSC) in Docket No. 06-101-U and the Tennessee Regulatory Authority (TRA) concerning proposed changes in rates and tariffs for retail electric service, attached are the original and 13 copies of the APSC Order No. 10 issued June 15, 2007 in Docket No. 06-101-U, reflecting the decision of the APSC on EAI's proposed retail rate request.

Pursuant to the APSC Order, EAI is preparing compliance tariffs for filing with the APSC which will be subject to APSC review and approval prior to implementation. Once the proposed rates are approved, EAI will file the final approved rates with the TRA for its consideration and approval for implementation.

If you have any questions, please do not hesitate to call me at 501-377-5489.

Sincerely,

William R. Morgan

William R. Morgan, Manager
Arkansas Regulatory Affairs

WM/tj
Attachment

ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ENTERGY ARKANSAS, INC. FOR APPROVAL OF CHANGES IN RATES FOR RETAIL ELECTRIC SERVICE	))))	DOCKET NO. 06-101-U ORDER NO. 10

ORDER

Summary

On August 15, 2006, Entergy Arkansas, Inc. ("EAI") filed in this Docket its Application seeking an increase in the rates it charges its Arkansas retail electric customers. As later amended, EAI seeks a retail revenue requirement increase of $106,534,000 or approximately 11.79% above its current authorized retail revenue requirement. However, based upon the evidence presented in this Docket, the Commission finds that EAI's retail revenue requirement is excessive and should be reduced by approximately $5.67 million effective as of June 15, 2007. Among other adjustments the Commission denied EAI's request for an 11.25% return on equity. Instead, the Commission set EAI's return on equity at 9.9%.

The Commission also denied EAI's request to recover a number of expenses from its ratepayers, including reducing the level of incentive pay and stock options requested by EAI by over $21 million, and by rejecting EAI's request for its ratepayers to pay for entertainment expenses which included tickets to sporting events and concerts, golf balls and golf tournament expenses, and dinners and alcohol to entertain political figures.

Further, the Commission approved EAI's request to recover costs relating to projects and organizations that promote new technologies and research and development investment. The Commission indicates its support for the development of new technologies which could provide more efficient utility operation that will lead to direct ratepayer benefit. The expenses that the Commission's order allows EAI to recover include the cost of its recently-deployed "broadband over power lines" project which is designed to study the feasibility of utilizing this new technology to enhance service delivery, outage detection and service restoration, as well as the potential future deployment of cost-effective and efficient demand response technology and advanced metering capabilities.

Other recoverable cost items that promote research and development include EAI's membership in the Electric Power Research Institute and the Southeastern Electric Exchange, as well as the percentage of EAI's membership dues for the Edison Electric Institute and Nuclear Energy Institute which are not related to promotional or lobbying activities. These recoverable costs were directed tied to ratepayer benefit. The Commission's order further allows Entergy to recover all of its costs to comply with the Commission's new corporate affiliate rules.

The Commission also conditionally approved a new Production Cost Adjustment Rider ("PCA"), which is designed to allow for the recovery of the current cost mandated by the Federal Energy Regulatory Commission ("FERC") under Entergy's System Agreement. This PCA will be reviewed annually as a part of an Annual Earnings Review ("AER") process which will, among other things, include a review of all of EAI's actions towards withdrawing from or satisfactorily amending its System Agreement that is the basis of the FERC-ordered rough production cost equalization payments. Any excess earnings identified through the AER process will be credited to ratepayers through the PCA Rider.

With respect to these FERC-ordered payments, the Commission reiterates its intent to continue to fight the FERC order which requires EAI to make payments to other Entergy operating companies. The Commission acknowledges that existing U.S. Supreme Court precedent establishes federal preemption over this Commission regarding recovery by EAI of the FERC required production costs payments to the other Entergy operating companies.

Finally, the Commission rejected EAI's proposed Capacity Management Rider as premature and not supported by substantial evidence. The Commission also amended EAI's Energy Cost Recover Rider ("ECR") and, as amended, allowed the ECR to continue for an additional year subject to the same limitations and conditions applicable to its approval of the PCA.

Procedural History

The parties to this proceeding are: Entergy Arkansas, Inc. ("EAI" or the "Company"), the General Staff of the Arkansas Public Service Commission ("Staff"), the Attorney General of Arkansas ("AG"), the Arkansas Electric Energy Consumers ("AEEC")[1], Kroger, the Commercial Group[2], and the Federal Executive Agencies ("FEA").

---

[1]Members of AEEC are Acme Brick Company, Albemarle Corporation, Almatis, A. Tenenbaum Company, Inc., Arkansas Steel Associates, Bibler Brothers, Inc., Chemtura Corporation, CMC Steel – Arkansas, International Paper Company, Lion Oil Company, Norandal USA, Inc., Potlatch Corporation, Producers Rice Mill, Riceland Foods, Inc., Riviana Foods, Inc., Stratcor Incorporation, Temple-Inland Forest Products, and Weyerhaeuser Company.

[2]Members of The Commercial Group are JC Penney Corporation, Inc., Lowe's Home Centers, Inc., and Wal-Mart Stores, Inc.

On August 15, 2006, EAI filed in the above-styled Docket its Application for a general increase in the rates it charges for retail electric service[3]. In support of its Application, EAI filed the Direct Testimony and Exhibits of its witnesses, Mr. Hugh T. McDonald, Mr. J. David Wright, Mr. Phillip B. Gillam,[4] Mr. Gordon D. Meyer, Mr. Greg J. Grillo,[5] Mr. Roger A. Morin, Mr. Robert R. Cooper, Mr. Steven M. Fetter, Mr. Roger Q. Mills, III, Mr. Michael J. Goin, Mr. Michael M. Schnitzer, and Mr. Paul R. Ford.

The Commission issued Order No. 3 on September 14, 2006, suspending EAI's proposed rates and setting the initial procedural schedule. Order No. 4, issued on October 2, 2006, amended the initial procedural schedule and directed the Staff and Intervenors to file Direct Testimony by February 5, 2007; EAI to file Rebuttal Testimony by March 5, 2007; Staff and Intervenors to file Surrebuttal Testimony by March 26, 2007; and EAI to file Sur-Surrebuttal Testimony by April 2, 2007. The parties were further directed to file a detailed Joint Issues List by April 8, 2007. Order No. 4 also set an evidentiary hearing to begin April 24, 2007, at the offices of the Commission in Little Rock, Arkansas, and set public comment hearings to be held May 3, 2007, in El Dorado, Arkansas, and May 8, 2007, in Batesville, Arkansas. By Order No. 7, the Commission postponed the evidentiary hearing set for April 24, 2007, by one day, rescheduling the hearing to begin on April 25, 2007.

Pursuant to the procedural schedule, on February 5, 2007, the Staff filed the Direct Testimonies and Exhibits of its witnesses Mr. Robert H. Swaim, Mr. Clark Cotten, Ms. Anita J. Marshall, Ms. Elana Davis, Mr. Larry Walker, Ms. Adrienne R. W. Bradley,

[3]EAI subsequently filed amendments to its Application on August 23 and August 25, 2006.

[4]EAI witness Gillam filed a revised Exhibit PBG-6 on December 7, 2006.

[5]EAI Witness Grillo filed *Supplemental Direct Testimony* on October 10, 2007.

Ms. Tanya Plunkett, Ms. Donna Gray, Mr. Jeff Hilton, Mr. Ralph C. Smith and Ms. Alice D. Wright. Also on February 5, 2007, Testimony and Exhibits were filed by AG witness Mr. William B. Marcus, by AEEC witness Mr. Randall J. Falkenberg, by the Commercial Group witness Mr. Glen E. Gregory, and by Kroger witness Mr. Kevin C. Higgins.

On March 5, 2007, EAI filed the Rebuttal Testimonies and Exhibits of its witnesses McDonald, Wright, Gillam, Morin, Meyer, Fetter, Grillo, Schnitzer, Cooper, Mr. Richard A. Lynch, Mr. Kurtis W. Castleberry, Mr. William M. Mohl, Mr. William A. Eaton, Mr. Kevin G. Gardner, and Mr. Jay A. Lewis.

On March 26, 2007, Staff filed the Surrebuttal Testimony and Exhibits of its witnesses Davis, Cotten, Plunkett, Swaim, Smith, Walker, Wright, Hilton, Bradley[6], Marshall, and Gray. On that same date, the AG, AEEC, the Commercial Group, and Kroger, and the FEA filed the Surrebuttal Testimony and Exhibits of their respective witnesses, Marcus, Falkenberg, Gregory, Higgins and Mr. Larry Blank. Staff witness Hilton subsequently adopted the Direct and Surrebuttal testimonies of Ms. Plunkett at hearing.[7]

On April 2, 2007, EAI filed the Sur-Surrebuttal Testimonies and Exhibits of witnesses Mohl, Meyer, McDonald, Grillo, Gillam, Schnitzer, Wright, Morin, Lewis, Fetter, Castleberry, and Lynch.

On April 9, 2007, the General Staff, on behalf of all parties, filed the Joint Issues List and thereafter, on April 23, 2007, filed an Amended Issues List.

---

[6]On March 29, 2007, Staff witness Bradley filed an Errata sheet, replacing page 6 of her Surrebuttal Testimony.

[7]References cited to Ms. Plunkett in this Order are to her pre-filed Direct and Surrebuttal Testimonies which were fully adopted by Mr. Hilton who sponsored the positions contained therein and was subject to cross examination on those positions.

On April 25, 2007, the evidentiary hearing on EAI's Application was commenced at the Offices of the Arkansas Public Service Commission (the "Commission" or the "APSC") in Little Rock and continued through May 4, 2007.

Pursuant to Ark. Code Ann. §23-2-103 (b), public comments were heard by the Commission during the evidentiary hearing in Little Rock, Arkansas, and during public comment hearings in El Dorado, Arkansas on May 3, 2007, and in Batesville, Arkansas on May 8, 2007. During the Little Rock evidentiary hearing six individuals commented on EAI's rate case Application. Of those, five spoke in favor of EAI's Application and one spoke requesting that the Commission keep in mind the impact of the issues before it on low income Arkansans. During the El Dorado public comment hearing three individuals commented on EAI's Application. All three supported the Application. During the Batesville public comment hearing five individuals commented on EAI's Application. Of those, four spoke in favor of EAI's Application and one individual urged the Company and the Commission to begin to focus attention on renewable energy and distributed generation. In addition the Commission received a total of thirty-five email or telephone comments on EAI's Application. All thirty-five opposed approval of the Application.

Though highly valued by the Commission the "public comments" of utility customers do not rise to the level of substantial evidence upon which the Commission is required by law to base its decision. The Commission cannot base its decisions upon the public comments of utility customers without violating the due process rights of the utility or other official parties to the rate case proceeding. Public comments are not subject to pre-hearing discovery by the official parties, and are not subject to adversarial cross-examination by the official parties during the evidentiary hearing. Thus, public comments do not constitute substantial evidence upon which the Commission can lawfully base its rate case decisions. The rate case decisions of the Commission must be based upon substantial evidence of record and must fall within the rate case boundaries or parameters prescribed by the Constitution of the United States as interpreted by federal and Arkansas courts. Although not substantial evidence of record, the Commission does take such public comments into consideration in its efforts to reach a balanced rate case decision that is lawful and fair to both the utility and its customers. Public comments can certainly be helpful to the Commission regarding quality of service issues, as well as cost allocation and rate design issues that can be decided within a "range of reasonableness." However, even these issues must be supported by substantial evidence of record.

Revenue Requirement Calculations, Cost of Service and Rate Design

The primary purpose of this docket is to determine whether EAI is entitled to an increase in its base rates for retail electric service. Unlike automatic adjustment clauses or riders, base rates are fixed by the Commission and do not vary from rate case to rate case. Base rates are determined by first establishing the appropriate retail revenue requirement. The revenue requirement is calculated taking into consideration the expected, normal level of utility-related expenses plus an appropriate rate of return on the expected, normal level of rate base. Rate base is the utility's financial investment in utility-related assets, both long- and short-term. The rate of return is calculated using the weighted cost of funds of the utility, made up of the proportional equity return, or profit, and related income tax, cost of debt, and cost of other liabilities, including those which are available at zero cost. Expenses, investment, and cost of funds are measured based on a utility-selected test year of actual costs, adjusted to recognize all known and measurable changes occurring within 12 months following that test year.

Once the revenue requirement is established, it is then assigned or allocated between the utility's Arkansas jurisdictional operations and any other jurisdiction, with the Arkansas allocated revenue requirement then assigned or allocated to each of the utility's rate classes under this Commission's jurisdiction. Components of the revenue requirement are assigned and allocated inter-jurisdictionally and to each class either directly to the jurisdiction or class incurring the cost or using factors which appropriately reflect general cost causation.

Rates are then established for each rate class using the amount of revenue requirement allocated to each class. Rate design differentiates customer related costs from those used to meet demand on the system and those used to provide each unit of energy. The resulting rate structure for each class will, where appropriate, reflect customer charges, demand charges, or unit of energy charges.

EAI's Rate Request

By its Application, EAI initially requested an increase in its current retail rate schedule revenues[8] of $150,366,000 based on its calculated revenue requirement of $1,053,942,000 (Minimum Filing Requirements ("MFR") Schedule A-1, ln 13), for an overall increase in its Arkansas retail rates of approximately 14.23%[9]. Subsequently, EAI amended its request in its Rebuttal Testimony, adjusting its proposed rate schedule

[8]Current rate revenues for Arkansas retail service, as reflected on MFR Schedule G-1, page 1, are $903,576,000.

[9]$150,366,000 requested increase divided by $903,576,000 current rate revenues.

revenue requirement to $1,010,110,000 and its projected revenue deficiency to $106,534,000 resulting in an increase in its current Arkansas retail rates of 11.79%.[10] EAI's projected revenue deficiency or rate increase is based on the Company's estimated pro forma rate base of $3,654,345,000, rate schedule revenues of $903,576,000, expenses of $771,188,000, other revenues of $37,435,000 and a required overall return of 6.42%, which is calculated using an equity return of 11.25% and a capital structure with a debt to equity ratio of 44% to 56%.

The Staff submits a fully developed EAI revenue requirement[11] in which it recommends a rate schedule revenue requirement of $925,794,000, with an expected revenue deficiency or rate increase of approximately $2,005,000. Staff's recommended $2,005,000 rate increase is based on a pro forma rate base of $3,693,152,000, operating revenues of $960,414,000, expenses of $755,621,000, and other revenues of $36,624,000. (T. Ex. 1146) Staff proposes an overall rate of return of 5.58%, which is calculated using an equity return of 9.90% (T. 829) and a capital structure with debt to total capital ratio of 52% to 48%. (T. 849) Staff's recommended rate schedule revenue requirement is approximately $84,316,000[12] less than that proposed by EAI.

As provided in the Amended Issues List, contested revenue requirement components are the capital cost, including equity return, the debt to equity ratio, adjustments to the Entergy Money Pool, and use of the Modified Balance Sheet Approach ("MBSA"), with the related elements and levels of zero-cost funds; rate base,

---

[10] T. Ex. 903.

[11] The AG and CEUG each addressed certain components of EAI's proposed revenue requirement request.

[12] Staff's rate schedule revenue requirement of $925,794,000 less EAI's rate schedule revenue requirement of $1,010,110,000.

including pro forma plant and retirements and related accumulated depreciation, the levels and elements of Working Capital Assets ("WCA"), the recognition and treatment of certain costs deferred by EAI and included in rate base for prospective amortization; and expenses, including pro forma depreciation, payroll levels, incentive pay treatment, pro forma levels of storm damage expense, treatment of certain civic and industry organization dues, donations, and club memberships, costs related to Affiliate Rules compliance, Director and Officer liability insurance expense; other revenues; and income tax, including the prospective application of the normalization method for taxes and the manufacturing deduction, for calculation of both income tax expense and as part of the gross conversion factor.

Other contested issues include billing determinant levels and related revenues and cost of service allocations; overall cost of service methods affecting inter-class allocation of production costs, transmission costs, the storm damage reserve; certain customer service and service revenue accounts; and certain tariffs and riders, including EAI's proposed Production Cost Adjustment ("PCA") rider, Capacity Management ("CM") rider, Energy Cost Recovery ("ECR") rider, Irrigation Control Service rider ("M25"), Service Extension tariffs, and tariff issues related to EAI's exemption to the Commission's Master Metering rules. Also contested is the wholesale/retail allocation and the recovery of Entergy System Agreement payments ("FERC Payments") as ordered by the Federal Energy Regulatory Commission ("FERC") in its Opinion 480 and 480-A[13] (the "FERC Decision").[14] (T. 2842)

[13]Opinion No. 480,111 FERC 7 61,311, *afd* Opinion No. 480-A, 113 FERC 7 61,282 (2005).

[14]As a result of the FERC Decision, EAI will be required to make payments to other Entergy Operating Companies ("EOCs") for certain imbalances in production costs among the EOCs to begin in June, 2007,

Revenue Requirement

Cost of Capital

The purpose of the cost of capital or rate of return calculation is to compensate the utility for its costs of capital used to finance its investment, or rate base. Those sources are generally on the liabilities side of the balance sheet, while the rate base generally encompasses items on the assets side of the balance sheet.

Generally, there are four main components to the capital structure used to calculate the overall cost of capital, or rate of return: common equity, preferred stock, debt, and accumulated deferred income taxes ("ADIT"). Common equity represents the investment made by the common shareholders; preferred stock is a type of financial instrument with some characteristics of equity and some characteristics of debt; debt encompasses specific long-term and short-term sources of debt; and ADIT is a zero-cost source of capital which reflects timing differences in the calculations of income taxes. Depending on the utility, other capital components may be included.

The various capital components are weighted by the respective proportions in the overall capital structure, each capital proportion is then multiplied by its capital cost, and then summed over all capital components to determine the rate of return. Generally, all of the capital costs, except for the cost of common equity, are readily obtainable from financial and accounting records; the cost of common equity must be inferred from market data.

---

pursuant to the Company's proposed Compliance Filing now pending before the FERC. The EOCs include: EAI; Entergy Gulf States, Inc.; Entergy Louisiana, LLC (formerly Entergy Louisiana, Inc.); Entergy Mississippi, Inc.; and, Entergy New Orleans, Inc.

Cost of Common Equity

The purpose of the cost of equity calculation is to allow the utility the opportunity to earn a return that is commensurate with the returns earned by companies of comparable risk. This will allow the utility the opportunity to attract capital on financially reasonable terms and compensate it for that portion of its capital. Unlike other components of the cost of capital, the cost of equity, which is designed to reflect investors' expected return, can only be estimated.

Because the cost of equity is not explicitly stated, it must be inferred from a variety of market data, with the assistance of expert witnesses. A number of methodologies for calculating the estimated cost of equity are used by the witnesses in this case; which include: (1) the Discounted Cash Flow ("DCF") methodology; (2) the Risk Premium methodology; (3) the Capital Asset Pricing Model ("CAPM") methodology; and (4) the Comparable Earnings methodology. Each of these methodologies, with each witness's corresponding results and recommendation, is considered in turn.

The parties to this proceeding recommended various costs of equity allowances. EAI witness Morin recommended a cost of equity of 11.25%. (T. 363) Staff witness Gray recommended 9.9%, which is the midpoint of her recommended range of 9.6% to 10.2%. (T. 830) AG witness Marcus recommended 9.5% (T. 672) and Commercial Group witness Gregory recommended 10.0%. (T. 588) While allowed return on equity ranges may be inferred from the testimony of the witnesses, Staff is the only party that explicitly stated a range. (T. 840, 873-874)

Discounted Cash Flow Methodology

The DCF methodology calculates the cost of equity as the sum of the dividend yield and the investor-expected growth rate (or growth rates, if a non-constant growth rate model is employed). The growth rate is a key component of the formula, and there is not one generally-accepted source for determining this growth rate. Hence, cost of equity witnesses must reasonably infer the investor-expected growth rate from published data.

Additionally, the DCF Methodology contemplates the use of a sample of companies comparable in risk to the Company in question, which in this case is EAI. The reason to use companies comparable in risk to EAI is the well-established principle of a positive correlation between investor-perceived risk and the required return on equity, or cost of equity. Generally, investors are risk averse, which implies that investors require greater returns from those common stocks that are riskier. Further, companies that are approximately equal in risk should have approximately equivalent required returns.

In developing risk-comparable samples, it is important to realize that there is not just one correct risk-comparable sample. A number of samples may be considered reasonable as long as each company in the sample is approximately equal in risk to the Company in question. Additionally, it is not necessary that each and every company in the sample be precisely equal in risk to the Company in question. However, the Commission would expect that, taken as a whole, the sample should be approximately equal in risk to the Company in question.

EAI witness Morin used two risk-comparable groups. First, he used a group of twenty-five electric and natural gas utility companies with predominately integrated utility activities, with bond ratings of Baa3 or above, with only parent companies, with market capitalizations greater than $500 million, and with at least 50% of their revenues from regulated electric utility operations. (T. 329, T. Ex. 97-105) Dr. Morin's dividend yield for this group is 4.4%. (T. 352, T. Ex. 109-111) Second, Dr. Morin used the electric utilities that make up the Moody's Electric Utility Index. His dividend yield for that group is 4.4%. (T. Ex. 115-117)

Staff witness Gray used two risk-comparable groups. First, Ms. Gray used a sample of ten companies listed in *Value Line Investment Survey*, with at least 75% of operating revenues from electric operations, with at least an S&P bond rating of BBB, with a stable or increasing dividend history, and not currently involved in merger activity. (T. 823-825) Those dividend yields are presented in Exhibit DG-12. (T. Ex. 378) Ms. Gray's second group is a sample of twenty-eight companies listed in *Value Line*, with current cash dividends, with no reductions in cash dividends in the last five years, and with no current involvement in merger activity. (T. 828) Those dividend yields are presented in Gray's Exhibit DG-16. (T. Ex. 382)

Commercial Group witness Gregory used two samples of risk-companies. First, Mr. Gregory used those with a *Value Line* Financial Strength Rating of B+ or greater, with five year earnings per share ("EPS") growth estimates from both Zach's Investment Service and Thomson Financial Services (First Call), with current cash dividends, with a current beta of 1.0 or less, and with no current involvement in merger activity. The second group was developed by removing the beta requirement. Those dividend yields are shown in Gregory's Schedules GEG-1 and GEG-2. (T. Ex. 208-209)

Company witness Morin argues that the Staff's common stock price data is not current enough since it uses stock prices reaching back thirteen weeks. Dr. Morin also argues that current stock prices should be consistent with the estimate of growth that is paired with it. (T. 395-396) Staff witness Gray responds that it is appropriate to use a fairly current price term and a price term that averages out daily aberrant prices. Further, Ms. Gray argues that a current stock price may be efficient in that it represents that day's investor-expected cost of equity; yet the allowed return on equity is set for a period much longer than one day. Ms. Gray explains that the stock price should be averaged over an appropriate period of time and should be a period after the publication of professional growth prognosticators, *i.e.*, Value line, Zack's, etc., since the stock price is influenced by those expected growth rates. (T. 878) The Commercial Users witness Gregory makes the same arguments as Ms. Gray. (T. 621-622)

The Commission agrees with Staff witness Gray that the DCF price term should be averaged, from a fairly recent time period, and from a period after the reporting of growth rate estimates. Ms. Gray's analysis accomplishes that and is an appropriate approach. From the record developed in this case by the Company, it is not clear that Dr. Morin met these conditions for the price term in his DCF analysis.

Another difference among the witnesses concerns the appropriate growth rate adjustment to the dividend yield term. Mr. Gregory makes no direct adjustment using the 2007 annual dividend projected for each stock as reported in recent editions of *Value Line*. Ms. Gray uses a quarterly adjustment where dividend yield is equal to D (1

+ g/4)/P. (T. 823, 877) Dr. Morin uses an annual adjustment where the dividend yield is equal to D (1 + g)/P. (T. 345)

Dr. Morin criticizes the quarterly adjustment and alleges that it understates the appropriate adjustment. (T. 392-396, 465-467) Ms. Gray responds that the model maintains consistency of the quarterly cost of equity with the revenue requirement determination and has been consistently used by this Commission for the past twenty years.

The Commission is unconvinced by Dr. Morin's arguments that the quarterly cost of equity approach is flawed and continues to believe that it is the appropriate approach. In particular, Dr. Morin alleges that the approach contains a serious error. (T. 467) Dr. Morin asserts that if the investor-required quarterly cost of equity is 3%, that the allowed return on equity should be (1.03)4 -1 = 1.1255- = 12.55%. Dr. Morin's interpretation is flawed. For example, if investors receive these quarterly returns as dividends, then investors have the opportunity to re-invest these dividends in the Company's stock, or other financial instruments as they see fit. Consequently, investors may implicitly take advantage of compounding through the receipt throughout the year of dividends every quarter. The quarterly cost of equity approach appropriately considers that early receipt of dividends.

All witnesses rely solely upon EPS forecasts by professional analysts. The Company uses EPS forecasts from *Value Line* and Zach's. Staff uses four different approaches for estimating the investor-expected growth rate for application to the DCF methodology. All involve projected growth rates in EPS derived from Value Line, Zach's and S&P. (T. 827-828) The Commercial Group witness uses projected EPS forecasts from Zach's and First Call. (T. 580) No witness uses historical data, book value per share growth rates, or dividends per share growth rates.

Company witness Morin alleges that Staff used a stale year, 2003, and stale *Value Line* data for purposes of calculating the g1 growth rate. (T. 401, 467-468) Staff witness Gray responds that g1 is the same as one of his growth rates and is based on recent *Value Line* issues (from August and September, 2006) wherein a base period of three years is reported. (T. 824, 879)

The Commission agrees with Ms. Gray. Dr. Morin apparently believes that Ms. Gray uses an older edition of *Value Line* (from 2003). That is not correct, as can be seen from the prefiled Direct Testimony of Ms. Gray. (T.824) Further, *Value Line* reports these three-year base estimates in current *Value Line* editions. This can be seen in Surrebuttal Exhibit DG-44, p. 9 of 12, for the example of Exelon. In the far left hand column annual rates of change in earnings are reported for the period "03-05" to "09-11". (T. Ex. 433) As can be seen there Exelon's growth rate is 6.0%. Dr. Morin misunderstands Staff's data sources and, hence, his criticisms are invalid. Additionally, Dr. Morin claims that g1 and g4 are the same projections, with g1 merely being an older version of g4. (T. 467-468) This assertion is incorrect since all of the data come from the same editions of *Value Line*, as discussed earlier, and are separate sets of growth rate data that investors would likely rely upon. Consequently, for all of the above reasons the Commission disagrees with Dr. Morin that Ms. Gray's g1 growth rates should be disregarded.

Ms. Gray criticizes EAI witness Morin's DCF analysis for the inappropriate inclusion of firms that were either rated below investment grade or involved in merger activity. Staff also criticizes the inclusion of the FPL Group, which has been involved in merger activity. Correcting Dr. Morin's Exhibits RAM-6 and RAM-7, RAM-8, and RAM-9 solely for those errors results in DCF cost of equity estimates of from 9.4 % to 10.0 %. (T. 873-874) Dr. Morin testifies that these firms should be included because they are currently either not below investment grade or are not currently involved in merger activity. (T. 417) Staff witness Gray responds that *at the time* that Dr. Morin performed his analysis these firms should not have been included. (T. 873, T. Ex. 425-436)

Company witness Morin also states that during periods when the ratio of a utility's market price to its book value ("M/B") is greater than 1.0, the DCF methodology understates the cost of equity. Dr. Morin testifies that this is particularly relevant at the present time when electric utility stocks are trading at M/B ratios above 1.0. (T. 354-356, 470) Commercial Group witness Gregory responds that investors are fully aware of the fact that regulatory commissions allow the return on the utility's investment and not on what the investor paid for his or her shares; consequently, the DCF method does not underestimate the cost of equity during periods when M/B is greater than 1.0. Further, if regulatory commissions were to make the M/B adjustments recommended by Dr. Morin, an endless cycle of increasing M/B ratios would result. Finally, Mr. Gregory notes that only a few regulatory commissions accept Dr. Morin's view. (T. 622-623)

Mr. Gregory's assessment on this point is correct. If the Commission were to make M/B adjustments, it would result in a never-ending cycle of increasing M/B ratios and a never-ending cycle of increasing allowed returns on equity. Consequently the Commission rejects Dr. Morin's argument that the DCF methodology systematically understates the cost of equity during periods when M/B is greater than 1.0

Further, on this point the Commission believes that the converse would also be true: during periods when electric utilities' M/B ratios are *less* than 1.0, the DCF methodology would *overstate* the cost of equity. We do not recall APSC-jurisdictional utilities, or for that matter EAI, making such an argument during the 1980's when electric utilities' M/B ratios were less than 1.0.

Risk Premium Analysis

The risk premium method is premised on the assumption that ownership of common stock is generally riskier than ownership of corporate debt. Because it is riskier, common stock requires a higher return than does corporate debt. If that difference in required return, the risk premium, can be adequately measured, it can be simply added to the measurable corporate bond rate to estimate the required return on common equity.

Company witness Morin utilized two risk premium analyses. One analysis was based on historical time series data using Moody's Electric Utility Index as a proxy. The second analysis employed allowed returns on equity.

For the historical analysis, Dr. Morin determined that the risk premium was 5.6% over long-term U. S. Treasury Bonds. With a current long-term U.S. bond yield of 5%, Dr. Morin derives a 10.6% risk-premium-based cost of equity. (T. 339)

Using allowed returns on equity relative to U.S. Treasury Bond yields over the period 1996-2005, Dr. Morin determines that there is an average 5.5% risk premium. He also states that there is a statistically significant relationship between risk premiums and interest rates using regression analysis. Utilizing the current 5% long-term U.S.

Treasury Bond yield in his regression model, Dr. Morin obtains a current risk premium of 5.9% and a 10.9% risk premium-based cost of equity. (T. 340-342, 419-420)

Staff witness Gray does not support the use of the risk premium approach as a primary indicator of the required return on equity because accurate measurement of the risk premium is a problem, and risk premiums are not stable over time. Ms. Gray testifies that estimates of the risk premium can vary based on the historical time period used for measurement, the underlying securities, and the end points used. She points to Dr. Morin's Exhibit RAM-3 where equity risk premiums varied from -37.34% to 71.96%, and where over 34% of the observations have negative risk premiums. (T. 831-832)

In her Direct Testimony, Ms. Gray also corrects a number of errors in Dr. Morin's historical risk premium data and, with those corrections, replicates his analysis in Staff Exhibit DG-23. This yields a historical risk premium of 4.99%. (T. 34-35) Adding this to her risk-free rate of 4.74% results in a 9.7% cost of equity. With regard to Dr. Morin's allowed return on equity analysis, Ms. Gray takes exception to his approach because six of the reported allowed returns on equity are the result of reaching either a stipulation or settlement. Nevertheless, using Dr. Morin's 5.54% risk premium with the risk-free rate of 4.74% supported by Staff produces a 10% cost of equity estimate. (T. 836)

Dr. Morin disagrees with Ms. Gray's risk premium discussion in a number of areas. First, Dr. Morin asserts that historical risk premiums are stable. Dr. Morin also states that, after correcting the errors and updating the results, the same historical risk premium of 5.5% to 5.6% was obtained. Dr. Morin testifies that using allowed returns on equity are accurate reflections of what relevant regulatory regard as fair and reasonable returns. Finally, EAI witness Morin corrects Ms. Gray's correction from 10%

to 10.28% and calculates a risk premium analysis with Ms. Gray's risk-free rate to obtain a 10.8% cost of equity. (T. 420-421)

AG witness Marcus quotes from a number of studies with findings of risk premiums in the 2.4% to 4.5% range. (T. 662-663, T. Ex. 285-318) Mr. Marcus criticizes Dr. Morin's historical risk premium analysis because it erroneously assumes a constant risk premium, uses data that precede the Great Depression, and is incorrectly estimated. (T. 664)

Commercial Group witness Gregory developed a risk premium of 4.20% based on the average risk premium from the most recent five years. Mr. Gregory adds this to the current single "A" rated utility bond yield of 5.73% to produce a risk premium-based cost of equity of 9.99%. This estimate is used by Mr. Gregory to confirm his DCF results. (T. 586-587)

Capital Asset Pricing Model

The Capital Asset Pricing Model ("CAPM") is an academic embellishment of the risk premium method which attempts to measure different risk premiums for different companies based on those particular risks of those companies. The CAPM is defined as "$K = Rf + \beta (Rm - Rf)$" where 'K' is the required return on equity, 'Rf' is the risk-free rate, 'Rm' is the market return, 'β' is the beta factor, and 'Rm –Rf' is the market risk premium. The market risk premium used in the CAPM is the difference between the overall stock market-required return and the risk-free rate. The beta of a common stock measures the volatility of the common stock price relative to the volatility of the stock market in general. A beta greater than 1.0 indicates that the stock price is more volatile than the market; a beta less than 1.0 indicates that the stock price is less volatile than the market.

Company witness Morin uses actual and forecasted yields on 30-year U.S. Treasury Bonds for the risk-free rate, which was 5.0% in his analysis. Dr. Morin uses a beta of .85 using the same risk-comparable group of electric utilities he uses in his DCF analysis. Dr. Morin checked that with the average beta of electric utilities in Moody's Electric Utility Index. For the market risk premium Dr. Morin uses 7.5%, which was based on a variety of forward-looking and historical studies of long-term risk premiums. Dr. Morin's CAPM result is 5.0% + .85 X 7.5% = 11.4%. (T. 323-335)

Dr. Morin also utilizes an empirical form of the CAPM ("ECAPM") in his analysis. Based on some of the academic literature, statistical tests purportedly demonstrate that the beta line is not as steeply-sloped as predicted in the theoretical CAPM. The implication of this approach is that firms with low-betas (below 1.0) earn returns somewhat higher than the theoretical CAPM would predict. Using the mathematics predicated on the ECAPM, Dr. Morin estimates his ECAPM as 11.7%. (T. 335-338, T. Ex. 139-155)

Commercial Group witness Gregory performed a CAPM analysis with a long-term risk-free U.S. Treasury Bond rate of 4.88%, a beta of .74, and a risk premium of 6.5%, which results in a CAPM cost of equity of 9.66%. (T. Ex. 211) Mr. Gregory disagrees with Dr. Morin's 7.5% risk premium. (T. 593-594) Mr. Gregory also notes a general deficiency in the CAPM methodology since reported beta calculations are strictly historical and do not predict future betas. Therefore, the forward-looking DCF methodology should receive more weight than the CAPM and other historic risk premium methodologies. (T. 626)

AG witness Marcus performed a CAPM analysis using a risk-free rate of 5.0%, a beta of .85, and a variety of risk premiums. Mr. Marcus generated a range of CAPM results of 8.05% to 9.71%. (T. 670-671)

Staff witness Gray performed a CAPM analysis as a reasonableness check on her DCF results. Ms. Gray used the 30-year U.S. Treasury bond yield of 4.74% for the risk-free rate, a beta of .80 to .85 based on the Entergy beta, and a market risk premium of 5.9% based on data from Ibbotson Associates. Ms. Gray's CAPM estimate is 9.5% to 9.8%. (T.833-835) Ms. Gray also replicated Dr. Morin's ECAPM analysis using her formula inputs, resulting in an ECAPM estimate of 9.8% to 10.0%.

Dr. Morin disagrees with all three of Ms. Gray's inputs in her CAPM analysis. In particular, Dr. Morin claims that the risk-free rate should be a current 4.9%, that the beta should be .90, and that the risk premium should be 6.5%. Dr. Morin then obtains a 10.8% estimate of his revision of Ms. Gray's CAPM analysis. (T. 409-411) Dr. Morin also disagrees with AG witness Marcus's CAPM analysis. In particular, Dr. Morin disagrees with Mr. Marcus' use of actuarial data, his market risk premium estimate, and his use of geometric averages in measuring expected return. (T. 428-430) Finally, Dr. Morin takes issue with Commercial Group witness Gregory's CAPM analysis, claiming that it understates the cost of equity by 40 basis points. (T. 446-449)

Other Methods and Checks

Commercial Group witness Gregory produces a Comparable Earning Test estimate of 10.2%. Mr. Gregory was the only witness to perform this test. (T. 585)

AG witness Marcus presented a study based on the estimated stock returns that Entergy and other utilities use to compute pension fund and nuclear decommissioning fund requirements. Mr. Marcus obtained return estimates of from 8.5% to 9.9%. (T. 656-670)

EAI witnesses Morin and Fetter allege that Ms. Gray's recommended allowed return on equity is harsh and below the mainstream of recently allowed returns on equity. (T. 382-385, 276-279) Ms. Gray responds that reliance upon the allowed returns of other Commissions is circular and that many of the reported allowed returns may be the result of stipulations or settlements with give and take among settling parties, including give and take with regards to the cost of equity. Ms. Gray also notes that that the information relied upon does not support the Company's request and that the 2006 allowed returns are in the range of 10.06% to 10.44%, which is more consistent with Staff's recommended range.

Flotation Cost Adjustment

A flotation cost adjustment is an addition to the cost of equity that attempts to reflect the issuance costs associated with a company's issuances of common stock.

Company witness Morin argues for a flotation adjustment to the cost of equity of 30 basis points. (T. 351-353) This adjustment would result in a $7 million annual impact on Arkansas ratepayers. (T. 596, 838) Dr. Morin argues that his floatation cost adjustment consists of two parts. The first reflects underwriting expenses and the second reflects market pressure. (T. 356-361, T. Ex. 156-166)

Staff witness Gray opposes the adjustment for underwriting expenses. Ms. Gray testifies that EAI's last common stock issuance was in 1983, that EAI actually repurchased common stock in 1990, that EAI currently has no planned issuance of securities in the pro forma year, and that Entergy Corp. issued no common stock shares from 2003-05. Ms. Gray also testifies that the shares issued in the past 10 years by Entergy were for the dividend reinvestment stock purchase plan, employee stock investment plan, and stock option expenses. Ms. Gray notes that: Entergy actually repurchased common shares during 1998-2005; Entergy has no planned issuance of securities during the pro forma year; Entergy plans to continue stock repurchases during the pro forma year; and Entergy has not publicly issued common stock for more than twenty years. (T. 839-840) Ms. Gray also opposes the market pressure component of the flotation cost adjustment recommended by the Company because it is difficult to disentangle the market pressure effect from other effects that could affect a utility's stock price at the time common stock is issued. (T. 839-840)

Dr. Morin responds to Ms. Gray by stating that there are a number of studies that support market pressure impacts of between 1% and 3%. (T. 422-423)

Commercial Group witness Gregory argues that a flotation adjustment is not needed in this case for two reasons. The first reason is that there have been minimal stock flotation costs over the past ten years. The second reason is that Entergy has decreased the number of shares outstanding during the past ten years. (T. 595-596) However, Mr. Gregory states that if the Commission finds that a flotation cost adjustment is warranted, he would recommend a ten basis point adjustment rather than EAI's request for an adjustment of thirty basis points. (T. 596)

Based on the evidence presented by Staff and the Commercial Group, the Commission finds that a flotation adjustment is not appropriate in this case.

Commission Determination of the Allowed Cost of Equity

The Commission heard extensive testimony on cost of equity. As this Commission has done in the past, we continue to rely primarily on the DCF methodology. While all methodologies used to estimate the cost of equity have weaknesses, in our opinion, the DCF methodology has fewer weaknesses than other methodologies. The risk premium and CAPM methodologies rely on a number on inputs about which witnesses disagree widely, including the risk-free rate, the risk premium, and the beta. Furthermore, this Commission does not rely upon the comparable earnings method because it relies upon earned returns, rather than required returns, and is circular in nature.

A major advantage of the DCF methodology is that it is more directly market-based. A key component of the DCF formula is the price term. The price term, if correctly calculated, is *forward-looking* and directly embodies the market consensus of a utility's risk, the time value of money, and the opportunity cost of money. As can easily be seen from the DCF formula, $K = D/P + g$, if risk increases, P decreases, and K increases. If the time value of money increases, P decreases, and K increases. If the opportunity cost of money increases, P decreases, and K increases. All of these results illustrate the simplicity of the DCF methodology. None of the other methodologies employ such a simple and direct market-based measure. Instead they all are *backward-looking*, relying upon a vast array of historical data, which may or may not be applicable in the future.

The only major issue that may arise in utilization of the DCF methodology is the estimate of the investor-expected growth rate. Witnesses often develop different estimates of the investor-expected growth rate. That is not true in this case.

With regard to the mechanics of some of the inputs to the DCF methodology in this case, the Commission agrees with Staff and the Commercial Group that the price term should be recent and averaged over a period of time to remove temporary price aberrations. The Commission also agrees with the Staff with regard to the quarterly form of the dividend yield term. As discussed above, a floatation cost adjustment is not adopted in this case. Finally, we agree with Staff with regard to the composition of EAI's two risk-comparable samples. After including Staff's corrections to Dr. Morin's DCF calculation, the result is a DCF cost of equity range of 9.4% - 10%, which is consistent with Staff's recommendation. (T. 830, T. Ex. 385-388) Commercial Group witness Gregory's DCF range (using medians and means) is 9.19% to 10.0%, which is also consistent with Staff's range. (T. 580)

With the corrections to Dr. Morin's DCF analysis, the DCF results by party are: EAI's range is 9.4% to 10.0%; Staff's range is 9.6% to 10.2%; and the Commercial Group range is 9.19% to 10.0%. The intersection of these three ranges is 9.6% to 10.0%. The similarity of these three witness's DCF cost of equity estimates implies that there is very little difference, if any, in their growth rate estimates.

The Commission also agrees with the corrections that Staff witness Gray made to Dr. Morin's risk premium, CAPM, and ECAPM methodologies, and in particular the risk premiums Dr. Morin relied upon. Based on those corrections, Ms. Gray calculates Dr. Morin's risk premium, CAPM, and ECAPM results as being from 9.5% to 10.0%. (T. 837)

Ms. Gray's own risk premium, CAPM, and ECAPM results are in the range of 9.5% to 10.0%. (T. 834-835) Commercial Group witness Gregory's risk premium and CAPM analysis produced a range of 9.66% to 10.0%. (T. 588) The AG presents evidence for a CAPM cost of equity range of 8.05% to 9.71%. (T. 671)

Given this Commission's primary reliance on the DCF methodology, and noting the results of the risk premium and CAPM methods as a check on the DCF results, the Commission finds that an allowed cost of equity in the range of 9.6% to 10.2% is reasonable in this case.

Furthermore, the Commission notes that there is one other matter that is important to consider. As noted by Ms. Gray, approximately 40% of EAI's revenues to be collected from EAI retail ratepayers will be collected through automatic adjustment clauses (the PCA, ECR, and other existing riders). There is no doubt that automatic adjustment clauses make utilities less risky, which implies a correspondingly lower cost of equity. In this case, 40% of EAI's revenues are at minimal risk of sales fluctuations or fuel cost fluctuations. Because of this reduced risk, we believe that an allowed return on equity of 9.9%, the mid-point of Staff's 9.6 to 10.2% range, is appropriate in this case. This return is commensurate with returns on utilities comparable in risk. Further, as discussed in our section concerning the capital structure, this return will maintain and support EAI's credit rating and allow it to continue to attract capital.

<u>Capital Structure/Debt to Equity Ratio</u>

A key aspect of the overall rate of return calculation is the determination of the appropriate capital structure. It is incumbent upon this Commission to ensure that the capital structure is reasonable, since it significantly affects the rates charged to the

Company's customers. The appropriate debt/equity ratio to be used in the capital structure is often contested by the parties since: (1) the cost of common equity is greater than the cost of debt and (2) the cost of equity is "marked-up" in the calculations of revenue requirement to cover income taxes, while the cost of debt is not. A smaller debt/equity ratio, other things being equal, will necessarily increase the overall cost of capital, and, ultimately customers' rates. In this case, EAI argues for a smaller debt to equity ratio than do the other parties.

EAI's basis for calculating its debt to equity ratio is a forecast of capital proportions as of June 30, 2007.[15] Furthermore, the actual debt to equity ratio as of June 30, 2006 reflected in the MFR, Schedule D-1 (a) is 45.5/54.5% rather than EAI's requested 44/56% ratio, which is a slightly higher debt proportion.

The parties in this case have recommended a variety of debt-to-equity ratios. They range from 44% debt and 52% equity as advocated by EAI to 52% debt and 48% equity as recommended by Staff and the AG. These ratios are expressed on a comparable basis, wherein the percentage equity component includes common equity and preferred equity, and the percentage debt component includes all interest-bearing debt, such as long-term debt, capital leases, and the Department of Energy ("DOE") obligation. The DOE obligation is a financial obligation that EAI has for spent nuclear fuel disposal services associated with the Company's nuclear units ANO-1 and ANO-2.

Staff witness Gray testifies that there are a number of reasons for rejecting EAI's proposed debt to equity ratio and using her hypothetical debt to equity ratio of 52/48%. First, in EAI's last two rate cases in which an order was issued making an explicit finding

[15] MFR Schedule D-1-(a)

on the overall cost of capital, the debt to equity ratios were 55/45% and 52/48% in Docket Nos. 84-199-U and 96-360-U, respectively. (T. 814-815) Additionally, in the two most recent Arkansas electric utility rate cases, the debt to equity ratios were 51/49%.[16](T. 815)

Ms. Gray testified that the four-quarter debt to equity ratio average ending September 30, 2006, for her risk-comparable sample is 52/48% and the four-quarter debt to equity ratio average ending September 30, 2006 for her broader industry sample is 52/48%. (T. 815) Ms. Gray also found that the debt to equity ratio of Entergy Corp., EAI's parent company, for the four quarters ending September 30, 2006 is 52/48%. (T. 816)

Ms. Gray notes that recognizing the parent-only amount of debt that Entergy Corp. uses for its investment in EAI yields a debt to equity ratio of 53/47%. (T. 816-817) Ms. Gray states that the consolidated parent corporation's total debt to total capital ratios were in the range of 51% to 61% for the years 1996 through 2001. (T. 860)

Ms. Gray testifies that the total debt to total capital ratios for EAI based on Form 10-Ks filed at the Securities and Exchange Commission ("SEC") were in the range of 53% to 57% for the years 1996 through 2001 (T. 860) and that, based on 2005 SEC Form 10-K results, the debt to equity ratio of Entergy and its other operating companies were in the range of 51% to 53%, while EAI's was at 48%, clearly outside this Entergy operating company range. (T. 860)

Commercial Group witness Gregory recommends a capital structure of 48.33% long-term debt, 1.24% preferred stock and 50.43% common equity. (T. 590)

---

[16]Docket No. 06-070-U, Oklahoma Gas and Electric and Docket No. 04-100-U, Empire District Electric Company.

In response to Staff's recommendation, EAI witness Lewis testifies that Staff's recommended debt to equity ratio would not meet Standard and Poor's ("S&P") Benchmarks for maintaining a BBB bond rating. (T. 215-216) Mr. Lewis calculated the impact of Staff's recommendation on three S&P ratios: (1) Funds from Operations ("FFO") to debt; (2) FFO to interest; and (3) debt to total capital, and testified that by adopting Staff's recommendation, these three ratios for EAI would be significantly and negatively impacted. Mr. Lewis states that this would have a detrimental effect on EAI's credit quality. (T. 216-217, 225-226) Further, EAI's witnesses argue that Ms. Gray's debt ratio calculations fail to utilize off-balance sheet obligations such as operating leases and post-retirement benefit obligations in her calculations of debt to equity ratios. (T. Ex. 51 and T. 263) Mr. Lewis also asserts that the negative outlook for Entergy Corp.'s credit rating is partially attributable to concerns about Arkansas regulatory climate. (T. 226)

EAI witnesses Lewis and Fetter contend that the adoption of Ms. Gray's hypothetical capital structure could lead to credit rating downgrades and higher interest costs over time. They also contend that such credit rating downgrades could result in EAI having to put up cash as collateral in various contracts as well as limiting access to capital markets, and that all of these results would be detrimental to EAI's customers. (T. 219, 266-267) In addition, EAI witness McDonald states there could be less capital investment by EAI and lower quality of service if Staff's proposed debt to equity ratio is adopted. (T. 126) However, during the hearing, Mr. McDonald, in response to questions from Staff Attorney Boyce, stated that EAI's commitment to reliable service quality will not diminish. (T. 198)

Mr. Fetter also asserts that adoption of Ms. Gray's recommendations on the cost of equity and debt to equity ratios would be perceived negatively by Fitch and Moody's in addition to S&P. (T. 269)

Ms. Gray responds to Entergy's bond downgrade assertions and provides calculations of various financial ratios for EAI using her recommended debt to equity ratio and cost of equity. She explains that her calculated FFO to interest ratio of 5.3 for EAI exceeds the S&P benchmark of 2.3 to 3.8 for EAI. She also explains that her calculation of the FFO to total debt ratio is 27%, which exceeds the S&P benchmark of 15% to 22%. Ms. Gray states that, utilizing her recommendation for the debt to equity ratio, total debt to total capital is 52%, which is within the S&P benchmark range of 50% to 60%. (T. 848, T. Ex. 410-411) She testifies that, even considering S&P's imputation of debt related to retirement obligations, her recommendations remain in the benchmark ranges for EAI. (T. 855, T. Ex. 412-413) Ms. Gray also states that imputation of debt could be significantly reduced because of Company witness Wright's statement that: "The Company actually paid over $80 million in July and September 2006 to reduce [the unfunded pension] liability" and that the actual September balance "is a debit of $24.6 million." (T. 852)

During the hearing, EAI witness Lewis agreed that using Ms. Gray's calculations, which include all aspects of Staff's cost of capital recommendations, would result in all of these ratios falling within S&P's benchmarks for BBB ratings. (T. 231)

Ms. Gray notes that the "negative" S&P outlook to which Mr. Lewis and Mr. Fetter refer is applicable to Entergy Corp. and each of its operating companies and reflects, among others, two factors unrelated to EAI's regulated operations: (1)

regulatory challenges relating to the separation of Entergy Gulf States into two companies; and (2) increasing exposure of non-regulated operations. (T. 854-855) Ms. Gray also explains that the Fitch credit report to which Mr. Fetter refers states that "on a stand-alone basis...the company's ratings are constrained by the linkage to its parent, Entergy Corp." Ms. Gray points out that EAI ratepayers should pay rates on a less leveraged capital structure when the rating of the parent is a limitation on the Company. (T. 855, T. Ex. 2)

Ms. Gray also testifies that over 40% of the Company's revenues (exclusive of decommissioning) are subject to adjustments outside the context of a general rate proceeding. She states that since S&P generally views non-rate case recovery mechanisms as positive, Staff's overall recommendations in this case should not be considered detrimental by S&P but should decrease uncertainty and have a positive impact.[17] (T. 856)

In response to EAI witness Fetter, Ms. Gray notes that the Moody's report reflects a stable, not negative, outlook for EAI and that Staff's recommendations are consistent with Moody's expectations. (T. 856)

EAI witness Wright presents a calculation based on Ms. Gray's recommended capital structure blended with EAI's actual capital structure to produce an 8.9% allowed

[17]The Commission takes administrative notice of the fact that over the past twelve months Entergy's common stock has risen from the mid-60's to a recent stock price of approximately $110 per share. This represents a price run-up of approximately 65% on an annual basis. Further, during the past twelve months Entergy's common stock price has achieved a high of $120 per share. (See financial information reported by Value Line and the Arkansas Democrat Gazette Newspaper.) Further, Standard & Poors recently affirmed its BBB corporate credit rating for Entergy Corp and its subsidiary operating companies including EAI. In addition the outlook on Entergy and its subsidiaries was revised to stable from negative. Regarding EAI's pending rate increase application Standard & Poors reports that it views the recovery by EAI of FERC allocated production cost payments as "important for EAI. Nevertheless, the overall effect should be neutral for Entergy's consolidated financial profile. (See Standard & Poors Research Update dated June 4, 2007.)

return on equity. (T. 537-538, T. Ex. 187) Ms. Gray agrees with EAI witness Wright's calculation and states that is the intended purpose of her adjustment. She explains that ratepayers should not be required to pay rates based on excessive levels of equity in the capital structure, and that if EAI chooses not to adjust its actual capital structure; the observation that 9.9% may not be achieved is irrelevant for purposes of determining the appropriateness of an adjustment. (T. 863) We agree.

The Commission finds that Ms. Gray's recommended debt to equity ratio is appropriate. It is consistent with the debt to equity ratios resulting from her risk-comparable and industry samples. It is also consistent with the debt to equity ratio of Entergy Corp. for the four quarters ending September 30, 2006 and the parent-only amount of debt that EAI's parent uses for its investment in EAI. Staff's recommendation is also consistent with the total debt to total capital ratios for EAI for the years 1996 through 2001; the consolidated parent's, Entergy Corp., total debt to total capital ratios for the years 1996 through 2001; the current debt to equity ratio of Entergy and its other operating companies; and maintenance of EAI's current bond ratings.

In this finding, the Commission also emphasizes three important considerations. First, it is important that there be congruence between the estimated cost of equity and debt to equity ratio. A lower debt to equity ratio decreases financial risk and, other things being equal, decreases the cost of equity. EAI failed to make that connection. Conversely, a higher debt to equity ratio increases financial risk and, other things being equal, increases the cost of equity. Ms. Gray's analysis accomplishes that congruence since her recommendations on both cost of equity and debt to equity ratio utilize her risk-comparable samples.

Although the phrase "hypothetical capital structure" is often used, sometimes it may be appropriate to refer to it as an "optimal capital structure." Given the correlation between debt to equity ratios and the cost of equity, it can be demonstrated that there is just one capital structure, the optimal capital structure, which minimizes the overall cost of capital. It is reasonable to assume that a risk-comparable sample should reflect "best practices" in a financial sense. Those "best practices" will encompass the "optimal capital structure" for the risk-comparable sample. By relying upon a risk-comparable sample to determine the debt to equity ratio, it can be fairly asserted that that is also the "optimal capital structure" for the utility in question.

Finally, this Commission is not necessarily recommending that the Company change its current debt to equity ratio to be consistent with Staff witness Gray's recommended hypothetical or optimum debt to equity ratio. That is the Company's decision to make. Ms. Gray's debt to equity ratio is an "adjustment" like other accounting adjustments that the Commission routinely makes. When the Commission disallows certain items from rate recovery we are not requiring the utility to cease making such expenditures. The Commission's responsibility is to determine which expenses are reasonable and necessary for the provision of utility service to ratepayers. The Commission's adjustment for the debt to equity ratio is similar: this is a determination regarding the appropriate ratio for ratemaking purposes.

Given our findings of a 9.9% allowed return on equity and our determination of the other capital component proportions and costs, the appropriate capital structure applicable to this case is that shown in Staff witness Gray's Surrebuttal Exhibit-30. (T. Ex. 400)

Entergy System Money Pool Lending

The Entergy System Money Pool is an internal financing mechanism whereby the Entergy Operating Companies ("EOCs") make short-term loans to each other depending upon their daily, weekly, and monthly needs.

Staff witness Gray recommends that an adjustment be made to EAI's capital structure to reflect the net lending by EAI to the Entergy System Money Pool. Ms. Gray explains that it is not clear that EAI ratepayers benefit from EAI's net lending position, and she adjusts $32,003,676 proportionally from externally-supplied funds (long-term debt, preferred stock, and common equity). The fact that EAI is a net lender to the other EOCs implies that EAI has incurred unnecessary additional sources of external financing (stock, debt, etc.) in order to make those loans to the other EOCs. EAI's ratepayers do not benefit from those loans; and yet they pay higher capital costs of external sources because of the loans. Consequently, it is appropriate that the amount of those loans be adjusted out of the externally-supplied funds. Although this amount has increased by an additional $14 million as of February 2007, Ms. Gray did not have this information in time to be included in her surrebuttal rate of return recommendation. (T. 821, 872; T. Ex. 373-374, 407-408)

EAI witness Wright contends that, given the significant disparity between Staff's and the Company's recommended common equity ratios, EAI will not have a material amount of cash available for investment in the money pool. Mr. Wright notes that any excess cash would presumably be used to make dividend payments in order to decrease the common equity ratio. (T. 536)

Ms. Gray responds that in the years 2002-2005, EAI could have issued additional amounts of first mortgage bonds to maintain a total debt to total capital ratio within the appropriate benchmark range. Ms. Gray notes that EAI could reasonably use debt financing in the future. (T. 871-873)

The Commission finds that Ms. Gray's money pool adjustment is appropriate. It is unacceptable for EAI's ratepayers to pay the relatively high costs associated with $32 million in outside capital in order to loan money to the other EOC at lower interest rates, and it is a direct subsidy of those other EOC's ratepayers by EAI ratepayers. This problem is particularly egregious at this particular time when EAI's ratepayers will be significantly subsidizing the other EOCs because of the FERC-mandated bandwidth remedy. Any additional subsidies from EAI to the other EOCs would only worsen a situation already unreasonable.

<u>Current, Accrued and Other Liability ("CAOL") Zero Cost Funds</u>

Accrued Interest Payable

EAI witness Wright and Staff witness Walker each included Accrued Interest Payable as part of zero cost funds. (T. 515, 1311) Accrued interest payable reflects the fact that the Company receives customer payments for interest on debt on a daily basis and prior to the time when the Company must make explicit interest payments to the bondholders. During that period of time the Company has interest-free use of the money provided by ratepayers, and it should be considered a zero-cost source of capital.

EAI witness Wright recommends that the Commission include the 13-month average of accrued interest payable in the capital structure. (T. 514-515) Staff witness Walker calculated his balance for this account using current debt cost and debt levels reflected in Staff's proposed capital structure. (T. 1311) The Commission adopts the Staff's approach, which uses updated debt outstanding and respective interest rate information consistent with Staff's surrebuttal capital structure recommendation. With the adoption, as discussed elsewhere in this Order, of Staff's capital structure recommendation, it is appropriate to use the pro forma interest data that is consistent with that capital structure.

Dividends Payable

No party disputed the inclusion of dividends payable in the MBSA. However, EAI disputes the calculation of the common dividend lag calculated by Staff witness Walker. Mr. Walker calculated the lag based on the declaration and payment dates made by Entergy Corp. to its investors. (T. 1299, 1311) EAI witness Wright asserts that the lag should be based on the declaration and payment dates made by EAI to its parent, Entergy Corp. (T. 514)

The Commission adopts Staff witness Walker's method for calculating the common dividend lag. The purpose of the inclusion of dividends payable in CAOL is that investors in Entergy stock recognize that there is a lag between the time that Entergy's dividends are declared and the time when dividends are actually paid. Because of this lag, and to compensate for the time value of money, investors require a slightly higher return on equity. Any cost of equity methodology that is market-based, such as the DCF method, will already include that effect in the estimated cost of equity. In this case we are estimating Entergy Corp.'s cost of equity, and using that as a surrogate for EAI's cost of equity since EAI has no market-traded common stock.

Consequently, to match the estimated cost of equity with the calculation of dividends payable it is appropriate to use the dividend payment lag of Entergy Corp.

Unfunded Pension Liability

EAI witness Wright includes in his calculation of CAOL a debit balance of $17.396 million in its accrual liability account, Unfunded Pension Expense,[18] representing the 13-month end average in that account, ending June 2007. (T. 1307) Staff witness Walker proposes that a credit balance of $30.086 million, representing the 13-month end average for that account, ending December 2006, be included for purposes of measuring the available cost-free funds for Unfunded Pensions. (T. 1307)

Mr. Walker contends that the debit balance requested by EAI is not representative of the normal level for that account, and that, based on the account's recent historical activity, the account normally carries a credit balance rather than a debit balance, and that his credit balance of $ 30.086 million is more indicative of that normal balance. (T. 1307) Mr. Walker explains that, from 2002 through year-end 2005, by making no payments into the account, EAI allowed the credit balance to increase by over 350%, from a credit balance of $20.1 million to one of $70.3 million. Mr. Walker notes that, primarily within the pro forma year, EAI made payments to that account which resulted in the $17.396 excess, which he asserts does not reflect a representative balance for that account. (T. 1308)

EAI witness Wright contends in his Rebuttal testimony that, assuming a Pension Expense and corresponding accrual of $23.2 million per year, it would take some 2 to 3

[18]Accruals are credited to this account each month, based on actuarial reports related to pensions, with the corresponding monthly debit made to Pension Expense. Payments for these Unfunded Pensions are then debited to the liability account when made, with the balance in Unfunded Pensions normally reflective of a credit balance. (T. 1307)

years before EAI would reach the credit balance of $49 million Staff had originally included as part of CAOL in Direct testimony and, thus, Staff witness Walker's balance will not be representative of this account when rates become effective. (T. 512-513, 1308) Responding to Mr. Wright's contention, Mr. Walker testifies that, Staff's currently proposed $30.086 million balance approximates the actual 5-year average, or midpoint, balance in that account. Thus, assuming a 5-year interval between rate filings, on average, EAI will recover all of its costs. Further, Mr. Walker notes that, should EAI duplicate its 10-year interval between its most current rate filings, EAI could actually collect more than that balance over the additional 5 years. (T. 1309)

In response, EAI witness Wright testifies that "Walker's approach would normalize a balance sheet account the same way you would normalize an expense account...(but) (t)he concept is not the same." (T. 561-J) Mr. Wright contends that "(w)e are looking to establish rate levels that take effect in mid-2007 to reflect costs that will exist in mid-2007...," (T. 561-J) so that, even assuming no additional payments, the projected 13-month average for this account through end of the pro forma year would be a debit balance of $2.1 million. That average balance, Wright further contends, is "surely the highest level at which this expense could logically be set for the purposes of establishing rates under any set of reasoning...." Mr. Wright states, that, however, "(t)o reflect reality, the Company recommends an average amount of (a debit balance) of ($17.4) million...to account for the contributions actually made in July and September." (T. 561-I – 561-J)

The Commission disagrees with Mr. Wright. The concept of normalization in ratemaking is not applicable only to expenses. [19] As a general rule, all components used to calculate rates should reflect the expected, normal level[20] of that component - a policy the Commission has consistently applied in its rate orders. With regard to measurement of working capital needs under the MBSA, the balances used should reflect the daily average expected balances of those accounts.

The record is clear. Staff witness Walker reviewed the account activity over a period of several years. The result is that his recommended $30.1 million credit balance approximates the actual average balance in that liability account over the last five years. (T. 1308-1309) The Commission also finds that EAI witness Wright provides no evidence to support a finding that Mr. Walker's recommended level, which was based on historical balances, is not reflective of the average, normal level expected for this account. Mr. Wright also does not assert that his recommendation of a $17.4 million debit balance for this account is indicative of expected normal daily levels. Mr. Wright does not dispute that, although recovering the expense for the entire period, EAI did not, for several years, make payments to reduce its corresponding Unfunded Liability, with that inaction resulting in the substantial annual growth of the liability - some $70 million by 2005. (T. 1308) Mr. Wright also acknowledges that EAI made large payments against this liability within the months immediately prior to and after the

[19]The Commission notes that EAI proposes a weather adjustment be applied to its billing determinants in this case. A weather adjustment removes any "abnormal" usage related to "abnormal" weather.

[20]The Commission would also like to point out that "normal" does not always mean "average". If it is reasonably known and measurable within the pro forma year that any rate base, income, expense, or capital structure account will prospectively and consistently reflect a higher or lower balance than that reflected in the test year, whether based on specific changes or based on historical trend analysis, such amount would be recognized, where appropriate, as the 'normal' level of that account for rate purposes.

filing of its current rate case, actually over-paying the liability, the result of which is the basis for the $17.4 million average debit balance EAI asks be used to offset its zero cost funds. (T. 512) Finally, Mr. Wright acknowledges that, although EAI recognizes some $23.2 million of Pension Expense in its current requested rate, EAI will, in the future, again withhold payments to fund Pension Expense and allow the credit balance in this liability account to increase. (T. 561-J)

The use of an expected, normal balance for this account neither disadvantages EAI nor thwarts EAI's opportunity to earn a fair return as Mr. Wright implies.[21] Staff witness Walker correctly points out that, assuming EAI rate filings are made on the average[22] of every five years, his recommendation for the Unfunded Pensions Expense balance will provide EAI the opportunity to recover its actual cost over that next five years. (T. 1308-1309)

EAI's proposal to include an aberrant debit balance in its liability account, Unfunded Pensions Expense, does not reflect appropriate ratemaking treatment. The proposal is therefore rejected. The Commission finds that Staff's recommended $30.1 million balance for Unfunded Pension Expenses is representative of the expected, average, and normal level for this account and is consistent with the corresponding Pension Expense recommended by both EAI and Staff. Therefore, the Commission approves $30.1 million for Unfunded Pension Expenses.

[21]Mr. Wright testifies that "the Company will not have the CAOL liability for unfunded pension expense proposed by Mr. Walker at the time rates go into effect and will not for at least two years." (T. 561-K)

[22]Averaging costs over expected periods between a utility's rate case filings is a standard and accepted method in measuring costs to be used to set prospective rates and does not constitute a form of "single-issue" ratemaking. (T. 1342-1344)

Storm Damage Reserve Account / Storm Damage Expense

EAI witness Wright includes, in his calculation of CAOL, an average debit balance of $46,585,000 for the liability account, Storm Reserve. (T. 1299) Mr. Wright recommends that this debit balance be used to offset CAOL or, alternatively, be included in rate base for a return. (T. 513) Mr. Wright argues that these costs are appropriately booked using "reserve accounting." According to Mr. Wright, under that accounting treatment, this liability account and its related expense, Storm Damage Expense, should, for ratemaking purposes, be treated differently than other Operations and Maintenance ("O&M") items which do not use reserve accounting. Mr. Wright testifies that, in reserve accounting, "the storm accrual approved in rates" is debited to Storm Damage Expense and credited to the Storm Reserve. When actual storm damage costs are incurred, they are debited against the accrued credit balance. (T. 502-503) According to Mr. Wright, for ratemaking purposes, any debit balance[23] in the account should either be added to rate base or be used to reduce CAOL. Additionally, Mr. Wright testified that an amortization of that debit balance, representing unrecovered costs, should also be added to the current storm accrual and recovered prospectively from ratepayers. Conversely, Mr. Wright asserts, any credit balance in the Reserve account would be included as an increase to CAOL for rate purposes. (T. 502-503)

Mr. Wright also recommends that the Reserve's related Storm Damage Expense be set at $29,720,000 for the pro forma year. (T. 508, 561-F) Mr. Wright testifies that the $29.7 million is based on three elements: (1) a proposed 5-year amortization of the Reserve's almost $50 million in prior period costs, or $9,854,000 per year (T. 508, 1310,

[23]The debit balance in the Storm Accrual Account represents storm costs incurred which were in excess of the annual expense accruals allowed in EAI's last approved rates.

1475); (2) $14,449,000 in the expected, normalized level of Storm Damage annual expense, the amount of which is not in dispute (T. 508, 1475); and, an extra "$5,417,00 for a 30-year amortization of the 2000 ice storm costs to build a reserve balance." (T. 508)

In support of this treatment, Mr. Wright testifies that "(t)he use of reserve accounting for storm costs is appropriate because of the nature of storm costs... (given that)... (t)he severity and number of storms are clearly out of the Company's control." (T. 503-504) Mr. Wright states that normalization[24] rather than the use of the reserve method "would improperly provide no recovery of previously incurred storm costs above the current level of accrual." (T. 504) Mr. Wright also advises that some 62% of these costs would be considered "production costs" in the calculation of payments required by the FERC in Opinions Nos. 480 and 480-A ("FERC Payment").[25] (T. 501) Finally, Mr. Wright testifies that, in EAI's last rate case, Docket No. 96-360-U, the Commission accepted the reserve method and used the then-credit balance in that account as an increase in the CAOL. (T. 561-C)

EAI witness McDonald also supports this rate treatment and urges the Commission to consider, from a public policy standpoint: (1) that service restoration is a health and safety issue as well as one of commerce, the disruption of which affects businesses, customers, and employees; (2) that, because Staff will thoroughly review any recovery request, EAI needs no other incentive to control costs; (3) that storm costs are

[24]Mr. Wright responds to Staff's recommendation to include only a normal, expected expense amount for Storm Damage cost. (T. 504)

[25]Pursuant to the System Agreement under which EAI operates with its affiliated utility Companies in Mississippi, Louisiana and Texas, FERC has proscribed a cost equalization formula, the results of which are that the higher the production cost experienced by each Entergy Operating Company, the lower its obligations to the other Entergy Operating Companies will be.

volatile and are caused by natural weather disasters, which are unusual and non-recurring events, and therefore are not comparable to other expenses; and (4) that the Commission should "encourage prompt action by utilities in emergency situations" by approving full recovery of these costs under reserve accounting. (T. 183)

Alternatively, Staff witness Walker, addressing the balance sheet's Reserve account, recommends elimination of the Reserve's debit balance from CAOL. Mr. Wright testifies that Staff has appropriately included a normalized level of these costs in Storm Damage expense and, therefore, there is no need to recognize the Reserve balance. (T. 1299) Staff witness Walker testifies that "EAI is not guaranteed 100% recovery of ... costs," and therefore it is not appropriate to allow rate treatment which would allow EAI to "retroactively recover these (past) costs both through a five-year amortization in expense and by either reducing the CAOL balances included in the capital structure or increasing the WCA balances in Rate Base." (T. 1310)

Staff witness Plunkett recommends approval of only the normal expected Storm Repair Expense of $14,449,000.[26] (T. 1470-1471) Ms. Plunkett recommends that the Commission reject both EAI's proposed amortization of past expense and its proposed accrual to build its reserve as not appropriate for rate purposes. Ms. Plunkett testifies that some $9 million or more of the request is for EAI's recovery of almost $50 million in prior period costs. Ms. Plunkett also testifies that EAI's request for $5.4 million annually to "build" reserves rests largely on the remote possibility that EAI will

[26] Ms. Plunkett calculated the normal, expected level of Storm Damage expense using a five-year historical average from which she had removed all abnormal storm costs, including those related to the 2000/2001 ice storms and Hurricanes Katrina and Rita. (T. 1470-1471)

experience two more "back to back hundred years storms."[27] (T. 1476-1479) Ms. Plunkett testifies that, notwithstanding EAI's use of reserve accounting or Storm Repair cost volatility, EAI provides no convincing reason to isolate and afford this one expense rate treatment that differs significantly from all other expenses. (T. 1476-1477) More appropriately, these costs should be included at a normal level which, witness Plunkett testifies, will provide EAI due incentive to control those costs in the future. (T. 1476)

AG witness Marcus recommends that the Commission allow annual recovery of $14.4 million in normalized expected expense but does not recommend approval of EAI's proposed $5.4 million accrual to build a reserve, citing concerns regarding both the propriety of allowing ratepayers to fund "additional" reserves as well as the timing of that additional ratepayer burden, given other cost increases expected for ratepayers. Mr. Marcus advises further that, although initially recommending EAI's proposed amortization of prior period costs as reduced for approximately $3.4 million in inappropriate charges, he no longer has a recommendation with regard to its inclusion in rates. (T. 752, 1273)

The Commission finds that EAI's proposed treatment of its Storm Reserve balances, if approved, would constitute retroactive ratemaking and, therefore, is rejected. The Commission makes this finding given both the almost $50 million[28] of admittedly prior period costs EAI accumulated in the Reserve account which it includes as a reduction to CAOL and its amortization of that same prior period cost as a current expense. (T. 1388-1389) The Commission also rejects EAI's proposed treatment for

[27]Ms. Plunkett notes that this is the description provided by EAI's current witness McDonald for the ice storms of 2000-2001 in his testimony in Docket No.01-084-U-U. (T. 1479)

storm costs as single-issue ratemaking and agrees with Staff witnesses Hilton and Walker that it is inappropriate to isolate only one component of revenue requirement for year to year measurement and to ignore the changes in all other components. (T.1391, 2209-2210) The Commission also finds EAI's proposed isolated rate treatment of this one element inconsistent with its own testimony. EAI witness McDonald, when asked about EAI's significant sales and revenue increases over the same period EAI accumulated its 'excess' Storm costs, responded that it is inappropriate to isolate the import of that growth to "just one component of the business," (T. 1553-1544) at the same time he requests isolated rate treatment for the same "one component of the business".

The Commission rejects EAI's proposed rate treatment for both the Reserve for Storm Damage and Storm Damage Expense and adopts Staff's recommendations. The Commission finds that Staff's recommendation appropriately includes a normal, expected annual level of Storm Damage costs of $14.449 million, the amount of which is not in dispute. (T. 1380-1388, 1470-1471) The Commission also finds that Staff's recommendation to reduce the related Reserve to zero is consistent with the averaging method Staff used in determining a normal expense level and will result in the Reserve reflecting, on average, a zero balance.

Transmission Reserve

EAI witness Wright testifies that Staff witness Walker incorrectly included a liability, Transmission Reserve, in Staff's proposed zero cost funds. As a reserve account, the Transmission Reserve is established when its related <u>expected</u> transmission

---

[28]Mr. Wright has included in CAOL a thirteen month-end debit balance for the Reserve Account in the amount of $46,585,000 which captures the amount EAI requests be amortized. (T. 513)

expense is recognized prior to actual expenditures, with actual expenditures used to offset the reserve when made. Mr. Wright testifies that Mr. Walker's inclusion of this liability is inappropriate because Staff witness Plunkett excluded the Transmission Reserve's related expense, resulting in "no cash flow impact for this accrual." Mr. Walker testifies, however, that Staff witness Davis made an offsetting adjustment to Ms. Plunkett's, adding back the corresponding expense. Mr. Walker further testifies that, in addition, he found that the Transmission Reserve account remains a liability on EAI's records as of December 31, 2006, and, consequently, that liability should remain in the calculation of EAI's zero cost funds. (T. 1312) Rebutting Mr. Walker, EAI witness Wright further testifies that Staff witness Davis' addition, although close in amount, was unrelated to Staff witness Plunkett's eliminated account, that the expense Ms. Davis included is not being accrued to the Transmission Reserve account, and, therefore, the Transmission Reserve should be eliminated. (T. 561-L) Staff witness Walker, however, explains that, in fact, Ms. Davis' addition to the transmission expense account was a replacement for the same costs removed by Ms. Plunkett, that it approximated the amount remaining on EAI's books, and, thus, Mr. Walker appropriately included the Transmission Reserve liability in his zero cost calculation. (T. 1360-1363)

The Commission finds that the reserve-related transmission expense has been accounted for by Staff, that the current per book information as of December 31, 2006, indicates there remains a balance in the Transmission Reserve, and although given ample opportunity to do so, EAI provides no exhibit or other substantive evidence to support its position that this per book liability should be removed from consideration as a zero cost element. Therefore, the Commission finds that Staff's inclusion of its calculated balance as a zero cost component is appropriate.

Rate Base

Plant

Plant Additions and Expenses Related to Broadband Equipment

Staff witness Davis testifies that EAI has increased its test year plant and expenses to recognize its expenditures for its Broadband Over Power Lines ("BPL") pilot program, adding more than $300,000 to rate base and $90,000 in expense. Ms. Davis testifies that, although expected to be operational by June 2007, EAI fails to provide sufficient evidence to verify the expected in-service date and recommends that the Commission disallow the BPL program costs, finding it premature for ratepayers to pay these costs during the evaluation stage. (T. 2067-2068) In addition, Ms. Davis testifies she is not making any finding as to the merits of the BPL pilot program, but is basing her recommendation on the uncertainty surrounding the in-service date of the program and the lack of evidence provided by EAI showing that it will benefit ratepayers. (T. 2072-2073) AEEC witness Falkenberg expresses concerns regarding the cost effectiveness of the program and its application for non-utility uses. AG witness Marcus suggests that it is more appropriate to address the implications of this type of pilot program in a separate docket outside of a general rate case. Both witnesses recommend that the Commission not approve such costs at this time. (T. 705-706, 1865)

EAI witness Castleberry testifies that its current BPL pilot program has reflected potential utility-related benefits in carrying data over power lines, including "remote metering, remotely connecting and disconnecting power at the customer premises, and enabling security cameras through the power line." He further asserts that the BPL pilot program is used and useful as a pilot which is currently operational and being tested in two separate locations. He testifies that its continuation will allow the testing of technology that "has the potential to improve electric reliability, reduce outage response times, and reduce operational costs." (T. 1614-1615)

The Commission finds that the potential utility reliability and cost benefits for ratepayers justify current rate treatment of EAI's BPL pilot program. The Commission notes that this technology may provide a means by which programs such as the Irrigation Switch Program and other demand response programs may be successfully offered, helping to reduce peak load, and to reduce overall capacity costs. (T. 1603-1604) However, the Commission appreciates the concerns expressed by the other parties in this docket regarding the potential non-utility application of the technology and potential ratepayer subsidy current ratepayer funding may provide. Although approving the BPL investment and related expenses in this case, the Commission reserves judgment regarding the future assignment of costs of implementation of the BPL program to ratepayers and the sharing of these technologies with non-utility functions, including appropriate pricing to those functions in the context of any future rate determination and under the Commission's Affiliate Transaction Rules.

Pro Forma Plant Levels

Staff witness Marshall testifies that, based on information provided by EAI, she has adjusted her proposed levels of pro forma plant to add certain plant as recommended by EAI and made certain mathematical corrections. (T. 1432-1434) With these changes, there are no outstanding issues among the parties related to the level of plant to be included in rate base. For simplicity, the Commission, therefore, adopts

Staff's most current recommendation for plant to be included in rate base, except that the Commission approves EAI's inclusion of broadband equipment.

<u>Accumulated Depreciation/Depreciation Expense</u>

Blytheville Turbine Removal Costs

Staff witness Marshall testifies that EAI has held $18,236,966 in costs it incurred in 2001 for refurbishing its Blytheville turbine and now seeks to transfer that full debit balance to the Accumulated Depreciation account, labeling it a cost of removal and thereby increasing rate base. Witness Marshall testifies that, as indicated in protected information supplied by EAI, the adjustment made by EAI is not appropriate, and recommends the Commission disallow this $18 million increase to plant. (T. 1424) Staff witness Plunkett testifies that, in addition to rate base treatment, EAI also requests current recovery of those costs in the amount of $3,647,393 annually, assuming a five year amortization, and she recommends that this amortization also be disallowed. (T. 1469)

In support of both the rate base and expense treatment, EAI witness Wright testifies that these costs were accounted for pursuant to appropriate accounting standards when EAI capitalized and posted them to accumulated depreciation for current rate treatment as an amortization. (T. 529-530) Further he states that Staff did not challenge the capitalization treatment of these costs during its audit of EAI's previously effective Regulatory Earnings Review Tariff, ("RERT") in the year in which they were incurred and therefore these costs should be included both in rate base and as an expense at this time. (T. 529-530, 532, 561-O) Mr. Wright testifies that Staff has not asserted and does not now assert that these costs are not legitimate, reasonable, and recoverable (T. 529), irrespective of when they were incurred (T. 530) or whether the facility's now discontinued lease payments are still reflected in current rates. (T. 561-P) He also asserts that this filing is EAI's first opportunity to request amortization of the capitalized cost. (T. 530) Mr. Wright recommends that the Commission allow "the recovery of this prudently incurred cost, and the cost should remain in rate base as it has been in previous earnings reviews." (T. 532)

In her Protected Surrebuttal Testimony[29] Staff witness Marshall describes the character or nature of the Blytheville turbine removal costs. With witness Plunkett's support, Ms. Marshall testifies that these costs were current charges when incurred in 2001 and are, therefore, out of period, non-recurring charges which should be removed from rate base with no related amortization allowed in current rates. (T. 1424, 1442, 1469, 1480) We agree with Ms. Marshall's description of those costs and with her conclusion regarding the appropriate ratemaking treatment for these costs.

The Commission finds that the record does not support EAI's proposal to include these 2001 lease-related costs in rate base nor does it support allowing the amortization of these costs in expense. Such costs are both non-recurring and clearly out of period and, based on the description provided by Ms. Marshall, are more appropriately deemed to be expense and, thus, should have been recognized in the year incurred. The Commission also finds that recognition in current rates of these six year old costs would constitute retroactive ratemaking[30].

---

[29]Marshall Protected Surrebuttal Testimony at page 7, lines 13-14. (T. 1453)

[30]The Commission notes again inconsistent treatment proposed by EAI. Mr. Wright recommends a capturing of these 6 year old Blytheville costs for current accrual, asserting that this is EAI's first opportunity to seek recovery. (T.530) However, Mr. Wright does not similarly propose that the Commission capture and accrue EAI's cost reductions related to the cessation of the Blytheville lease. Mr.

The Commission also rejects Mr. Wright's inference that Staff's lack of objection to capitalization of this expense in EAI's RERT filing provides assurance of future Commission approval of prospective rate treatment in a general rate case. (T. 561-O) The Commission finds, rather, that it was EAI's choice to capitalize these costs in its RERT filing, although it had originally accounted for such costs as an expense. (T. 561-O) If EAI had wanted Commission approval of these costs as an expense under its RERT in the year incurred or if it had wanted Commission approval at that time to create a regulatory asset for future recovery, EAI could and should have petitioned the Commission for that rate treatment. EAI chose not to do so. The Commission finds no evidence to sustain EAI's contention that it had received approval for the inappropriate rate treatment it now seeks. Accordingly, recovery of the Blytheville turbine removal costs are denied.

Union Power Partners LP - FERC Order

EAI witness Wright, responding to adjustments made by Staff witness Marshall, testifies that, pursuant to FERC Order in Docket No. EL05-1-000, EAI must refund by the end of the year certain credits previously recognized as a Contribution in Aid of Construction ("CIAC"). The result of that refund, he states, will be to increase overall plant by $6.9 million and increase Depreciation Expense by $101,466. (T. 542)

Wright dismisses the fact that the Blytheville Plant lease and maintenance and tax expenses costs, which are fully recognized in EAI's currently effective rates, ended for EAI in 1998 with the lease termination. (T. 1441-1442) Instead, Mr. Wright appears to recognize that such treatment of past cost reductions would be retroactive ratemaking and that irrespective of the fact that current revenues were designed to collect costs no longer being incurred, "it is the normal result of the ratemaking process that such recovery would continue." (T. 561-P) Mr. Wright appears to conclude, correctly, that capture of these heretofore unrecognized past savings for prospective rate treatment is inappropriate retroactive ratemaking. Had Mr. Wright been consistent, he would have similarly concluded that capture of the heretofore unrecognized past Blytheville costs for prospective rate treatment is also inappropriate retroactive ratemaking.

Ms. Marshall testifies that she has now incorporated that refund into her Plant balance and has adjusted her depreciation accrual and expense appropriately, but also notes that, as reflected on Mr. Wright's Exhibit JDW-10, he has applied incorrect depreciation rates in his calculation and, thus, her recommendation in this regard differs from that of EAI. She notes that the rates for these accounts were approved in EAI's last rate filing in Docket No. 96-360-U. (T. 1443)

Therefore, the Commission finds that Ms. Marshall's calculation appropriately incorporates the current, Commission approved depreciation rates while Mr. Wright's does not. The Commission adopts Ms. Marshall's calculation.

Depreciation Expense
Compliance with Ark. Code Ann. § 23-2-304(a)(8)(C) and General Plant

Staff witness Gray, referring to the findings of Staff witness Marshall, testifies that EAI has failed to file for approval of depreciation rates related to two accounts, 320.2, Land and Land Rights/Nuclear Production Plant and 330.2, Land and Land Rights/Hydraulic Production Plant. She notes that, for purposes of the revenue requirement in this case, Staff has accepted the rates which EAI has employed. However, Ms. Gray recommends that the Commission direct EAI to "prospectively comply with the provisions of Ark. Code Ann. § 23-2-304(a)(8)(C)", by seeking approval from the Commission for the change or addition of any new rates, and filing, if necessary a request for approval of interim rates. (T. 885-886)

Ms. Gray also notes that EAI appears to have adopted amortization accounting for its General Plant accounts and, although Staff has accepted the results for purposes of the revenue requirement within this Docket, Ms. Gray recommends that the

Commission direct EAI to file, with any new rate application, a fully substantiated and supported request for that change. (T. 886-887)

EAI witness Wright disputes Ms. Gray's contention that EAI employs amortization accounting, stating that EAI accounts for General Plant equipment by schedule "in accordance with the Uniform System of Accounts 18CFR Ch.1 Electric Plant Instruction 10, Additions and Retirements of Electric Plant paragraph B(2)..." and that "(t)his is a ministerial matter and not an issue that requires APSC approval or action. (T. 561-L) Further, he testifies, EAI continues to apply the General Plant rates approved in its last rate case. (T. 1223)

Ms. Gray, however, testifies that while EAI used the rates approved in the last docket, it was EAI's unilateral change to new retirement schedules, schedules based on asset lives other than those used in the currently approved rates, which in her "estimation (is) akin to amortization accounting." (T. 1223-1226)

The Commission finds Ms. Gray's explanation persuasive and directs EAI to seek, in its next rate filing, Commission approval pursuant to Ark. Code Ann. § 23-2-304(a)(8)(C) for any new rate or any change in rates it wishes to implement. The Commission further directs EAI to appropriately request approval between rate filings of an interim rate at any time that it adds plant which has no approved depreciation rate. As to EAI's change in its retirement schedule, the Commission finds that such a change constitutes a change which may result in amortization accounting and, therefore also directs EAI to address that issue fully in its next general rate filing.

Working Capital Assets for the Modified Balance Sheet Approach

It has been this Commission's practice to provide for the working capital needs of utilities in its calculation of revenue requirement. Various methods are used to measure those needs, ranging from the simple, such as inclusion of only a few, isolated short-term assets in rate base, to the complex, such as use of a fully developed lead-lag study ("LLS"). In this regard, the Commission has used the Modified Balance Sheet Approach ("MBSA"), either in the absence of a LLS or as a check of a LLS filed by a utility.[31] Simply stated, the MBSA includes all utility assets in rate base, the impact of which is to recognize the "lead" inherent in an asset, and, at the same time, includes, as a proportionate cost of capital, all liabilities in the return calculation, which effectively recognizes the "lag" inherent in a liability.

The MBSA recognizes three basic facts: (1) a utility has investments in assets other than plant which are necessary to provide utility service, and on which a return should be allowed; (2) a utility has sources of funds, other than equity and long-term debt, which should be included in the capital structure; and (3) all liabilities are fungible sources of funds that are used to fund each and every asset of the utility. A corollary of this third point is that zero-cost liabilities should be placed in the capital structure in calculating the utility's cost of capital.

The rationale for placing all liabilities in the capital structure with the MBSA is that all liabilities are sources of funds used to finance the assets of the Company. No distinction can be made as to which asset a liability is funding because the funds

[31]Order No. 7 of Docket No. 84-199-U.

provided by liabilities are fungible. Therefore, to determine the total cost of funds for the Company, the MBSA posits that we cannot ignore CAOL.

Coal Inventory

As noted by EAI witness Wright, EAI has adjusted its per book average daily balance for investment in Coal Inventory to reflect an annual average 43-day operational inventory, increasing the book balance by $5.76 million. Mr. Wright testifies that the current average investment reflected in its accounting records translates into a 30-day operational level only. (T 552) EAI witness Mohl testifies that the average 43-day operational level upon which witness Wright based EAI's working capital investment is a result of getting the average daily operational coal inventory using EAI's currently approved Coal Inventory Policy. (T. 1018-1019) Mr. Mohl also states that adopting the 43-day operational coal inventory does not mean that a full 43 days of inventory will be available each day, only that, on average, the inventory will reflect that level of supply. (T. 1023)

Staff has included, as discussed by Staff witness Walker, a 45-day burn inventory based on EAI's historical levels. Mr. Walker testifies that this level essentially reflects an operational "average burn" 45-day supply, rather than EAI's proposed 43-day "full burn" supply. (T. 1306, 1329-1330)

The Commission finds that, as requested by EAI, its working capital should reflect the average investment in its Coal Inventory resulting from its currently approved Inventory Policy, under the assumption that this level will be maintained prospectively, representing an average, normal level. The Commission, therefore, approves EAI's proposed balance in this regard. The Commission, however, also orders

EAI to maintain that average operational supply as indicated in its approved Inventory Policy. Any failing by EAI to maintain that average daily level, as required by its current coal Inventory Policy, will be deemed imprudent and in direct violation of Commission order.

Undistributed Stores Expense and Clearing Accounts

Staff witness Walker recommends the elimination of Undistributed Stores Expense and Other Clearing accounts from rate base. Mr. Walker explains that the amounts reflected in these accounts are temporary, more akin to Construction Work In Progress ("CWIP"), and will be assigned to plant as it is completed or to operating expenses as incurred. Witness Walker testifies that, because Staff has appropriately recognized through the end of the pro forma year all used and useful plant to which these costs are assigned and has also included the most currently known and measurable pro forma level of all expense to which these costs are assigned, it is not appropriate to include the temporary accounts in rate base. (T. 1304-1305, 1306)

EAI witness Wright recommends inclusion of these accounts in rate base. Mr. Wright testifies that certain charges are accumulated in a separate account and are applied to the appropriate plant or expense as they are incurred. According to Mr. Wright, this is a regular utility practice and results in an ongoing balance carried on the balance sheet that is not reflected in either plant or operations and maintenance expense and should be included for rate purposes. (T. 517-518) Mr. Wright notes that, in EAI's last rate case, Docket No. 96-360-U, Staff witness McDowell did not eliminate these balances and, therefore, concludes that Mr. Walker's adjustment is inconsistent with prior Commission practice. (T. 518)

Therefore, the Commission finds Staff's treatment of such accounts appropriate and consistent with recent Commission practice and adopts it here. The Commission finds that these costs, which pass through such temporary accounts, are fully and appropriately recognized either as part of rate base assigned to pro forma plant or in the pro forma expenses to which they are assigned. The Commission also finds that to also allow the balances reflected in these accounts to remain in rate base and earn a return would result in recognizing them for rate purposes twice.

Deferred Board of Directors' Benefits/Deferred Capacity Solicitation Costs

Staff witness Walker also recommends the elimination of deferred balances for Board of Directors' Benefits and Capacity Solicitation Costs. Mr. Walker testifies that, similar to clearing accounts, Staff has recognized the full pro forma level of the related expense and, therefore, the deferred balance should not be included in rate base. Mr. Walker also testifies that such treatment is consistent with past Commission findings and that the Commission has found that, while inclusion of the expense may be appropriate, the deferred balance would not be allowed in rate base for purposes of a return. (T. 1305, 1380-1381) EAI witness Wright asserts that each of the accounts reflect funds the Company must expend until such time that the expense is paid, thereby benefiting the ratepayer and should be included in rate base. (T. 510-511)

The Commission finds, as it did with regard to clearing accounts, Staff's treatment appropriate and consistent with prior Commission findings and agrees that, given that Staff has included a full, normal level of pro forma expense for the costs; the related deferred accounts should not be included in rate base to earn a return.

Non-Tax Expenses

Payroll Levels for Distribution and Transmission

Staff witness Hilton disagrees with EAI witnesses Wright and McDonald on appropriate payroll levels for the pro forma year. In calculating the expected pro forma payroll levels, Mr. Hilton testifies that he uses the most current information available. He further states that he initially used current payroll levels as of October 30, 2006, which reduced the per book payroll balances by $2,625,325. (T. 1499-1450) In his Surrebuttal Testimony, Mr. Hilton notes that he further updated his recommendation for payroll, which is now based on the number of employees as of January 2007, provided in data responses from EAI (T. 1511-1512), adding $308,098 to his original reduction to test year payroll of $2,625,325 (T. 1499-1450) for a total reduction of $2,933,423.

EAI witness Wright agrees with Mr. Hilton's payroll figures, except for Wright's proposed addition of 41 new personnel[32] to be hired for Distribution and 24 new personnel[33] to be hired for Transmission. Mr. Wright testifies that the addition of these employees would increase Mr. Hilton's recommended payroll expense by $3.602 million[34] on an Arkansas-only basis.[35] (T. 541) Mr. McDonald testifies that all distribution personnel and all but four transmission personnel have been hired by EAI, with all new personnel expected to be in place by the end of the pro forma year. (T.

[32]Mr. Wright testifies that EAI intends to hire 28 linemen, 5 meter service personnel, and 8 operations coordinators, for a total of $2.438 million. (T. 541)

[33]Mr. Wright testifies that EAI intends to hire 13 relay technicians, 9 substation repairmen and 2 operations coordinators, for a total of $1.164 million. (T. 541)

[34]The sum of the Distribution personnel cost of $2.438 million plus the transmission personnel cost of $1.164 million.

[35]Mr. Wright testifies that the increase for total company would be $4.044 million. (T. 542)

1548-1549, 1561) Mr. McDonald testifies that the Company appropriately planned for these additions and that "(i)t was determined that additional manpower was required to help ensure that (EAI) safely, effectively and efficiently provides reliable service to our customers." (T. 181)

Staff witness Hilton testifies that EAI failed to provide a total and balanced picture of personnel activity at EAI, providing information only on its new hires without providing the same information regarding transfers and terminations. (T. 2120) Mr. Hilton expresses concern that he only became aware of the unplanned payroll additions upon receipt of an addendum to EAI's updated response to an open data request. (T. 1510) He expresses concern that these positions bypassed normal budgetary and approval phases and that some of the hiring forms indicated that these positions were to be filled by relocated, not new, employees. (T. 1512) Mr. Hilton further expressed concern that EAI's data shows that, historically, overall payroll levels have changed little, with new positions being created and old positions being eliminated. And, he continues, even for EAI alone and ignoring inter-affiliate personnel transfers, "over the course of the test and pro forma year, there was a negative 39 employees that...when you look at the individual details, for that same period of time, there were 85 hires, 122 terminations, 19 transfers in and 21 transfers out. So certainly all things are going on at the same time and... (T. 2121)...thus, any revision to employee count should be done in the context of a full update, not an isolated adjustment." (T. 1511) Mr. Hilton acknowledges that he received EAI's response to his request for support for the new personnel on March 21, 2007, but also testifies that the response contained limited information and did not, as the data request asked, provide evidentiary support for the new hires. (T. 1511-1512) Mr. Hilton testifies that he has not received a complete update on overall payroll changes since receiving EAI's January 2007 update on March 14, 2007. (T. 2124)

The Commission finds that Staff's position regarding the proposed additions to pro forma payroll is balanced and appropriate. Staff acknowledges that, if it had received EAI's updated response to Staff's data request for total company payroll data, and had, after review, found that the information verified the new positions as the only change, the Staff would have routinely included those updates in its recommendation. (T. 2125-2126) The Commission finds that it is incumbent upon the utility requesting a change in its rates to timely provide full and complete information upon request. EAI has submitted a pro forma adjustment reflecting an incomplete picture of its expected payroll activity, despite the request from Staff to provide a complete picture. EAI has had ample opportunity to update both its February and March payroll information and has chosen not to do so. The Commission therefore finds that the data needed to make a decision to include these positions, from the perspective of the overall pro forma payroll level that is known and measurable, is not in evidence. Rather, the Commission finds that the Staff's proposed level is fully supported by the evidence and provides the best known and measurable level of expected pro forma payroll. Therefore, the Commission adopts Staff's position on payroll.

Incentive Pay/Executive Perquisites

EAI proposes to include "$14,432,069 for incentive compensation in O&M expense...of which approximately $2.0 million was paid by EAI, $6.0 million by ESI, and $6.6 million by nuclear operations...." (T. 689) Staff witness Hilton, addressing these incentive packages, explains that there are multiple compensation plans, some of which are tied to operational benchmarks with others tied to certain financial benchmarks. Mr. Hilton testifies that the plans which are "predominantly-financial" incentives will benefit both shareholders and ratepayers and, therefore, recommends that these costs be equally shared. Mr. Hilton explains that, for all Entergy companies, including EAI, all incentive plans are made up of performance measures, with at least 25% of any plan made up of the incentive measure called the Entergy Achievement Multiplier, or EAM.

Mr. Hilton explains that EAM "is a measure of Entergy Corporation's financial performance using earnings per share and operating cash flow." Because EAM is tied to financial performance and benefits both stockholder and ratepayer, Mr. Hilton recommends the Commission disallow 12.5 % of incentives for plans which tie 25% of goals to EAM, 25% of incentives for those which tie 50% of goals to EAM, and 50% of incentives for plans entirely tied to the EAI measure. Mr. Hilton further testifies that EAI also offers certain incentive stock options plans, with the criteria for those plans tied entirely to increased shareholder value and, thus, tied 100% to a financial performance measure. Mr. Hilton testifies that stock option incentive plans, which are tied entirely to financial performance, should also be shared equally between stockholders and ratepayers and, therefore, recommends the Commission disallow 50% of such costs. Mr. Hilton recommends a total disallowance of $4,928,926[36] in non-stock option incentives and $7,682,797 in stock options. (T. 1500)

---

[36]Mr. Hilton testified he corrected an error in his Direct testimony, in which he had erroneously included other personnel benefits to the incentive payments, thus reducing his originally recommended adjustment of $6,598,908 (T. 1500) by $$1,669,982 (T. 1510) to $4,928,926. (T. 1510)

AG witness Marcus testifies that he also measured these same incentives and recommends an equal sharing of costs for incentive plans which include some operational criteria for performance. Mr. Marcus asserts, and Mr. Hilton agrees (T. 1513), that "(a)s a general rule, it is not good public policy to include 100% of incentive payments in rates". Mr. Marcus states that, to allow 100% of these costs in rates cushions stockholders from the risk that the financial goals will not be met, noting that, should employees fail to meet the assigned goals and, thus, be paid no bonuses, 100% of those bonuses remain in rates, generating revenues which help offset any negative results of under-performance. Moreover, Mr. Marcus testifies that the benefits of good performance flow to shareholders in periods between rate case test years "... (with those) EAI bonuses, for Arkansas, heavily tied to the profitability of the parent company." (T. 691, footnote omitted) Mr. Marcus states that there are several general plans, some of which are tied to both financial performance and to operational performance and some tied entirely to financial performance. Mr. Marcus testifies that financial performance is a direct measure of shareholder value. Therefore, he recommends that for these plans the incentive payments be shared equally between ratepayer and shareholder. (T. 692) Mr. Marcus further testifies that Entergy also offers other compensation plans, including plans related to "restricted stock, stock options, and stock-based long-term incentive programs...(which)...are based entirely on stock price of the parent company." (T. 692) These plans, he states, are tied entirely to the financial performance and the stock price of EAI's parent, Entergy Corp. For these, Mr. Marcus recommends that the Commission disallow all of these costs as benefiting only shareholders. (T. 692) Mr.

Marcus therefore recommends that the Commission disallow $7,606,446 in the non-stock option incentives and $15,365,000 in stock option plans. (T. 692-693)

Mr. Marcus also recommends disallowances for certain perquisites provided EAI's Chief Executive Officer and the five top executives at Entergy Corp. which are allocated to EAI, including those for club dues, financial counseling, the corporate airplane, and a tax "gross-up".[37] Mr. Marcus testifies that these types of expenditures are unnecessary in light of salaries paid and should not be borne by ratepayers. (T. 693)

EAI witness Gardner recommends that the Commission allow all of the incentives because they are necessary to attract and retain professional and managerial employees in a competitive market. (T. 1660-1661) He notes that the level of compensation paid, including the incentives, are set at the 50th percentile of similarly situated companies (T. 1655-1656), and would, if not allowed, require increases in base salaries which do not provide employee performance incentive. (T. 1662) Mr. Gardner further testifies that strong leadership is needed not only for the company's financial success but also for its operational success. (T. 1663) Mr. Gardner concludes that the overall compensation packages at issue are consistent with market practice and that:

> These metrics include a combination of operational, customer service, financial, safety and individual performance measures to ensure an appropriate alignment between the customer, employee and shareholder. Thus, it is appropriate to include recovery of all costs related to these compensation programs... (and to eliminate any of them)...would place a disproportionate weight on the base salary component of the compensation package. (T. 1665-1666)

According to Mr. Gardner, by tying employee compensation to these financial incentives, EAI shares the risk of its financial success with its employees. If these

[37]Mr. Marcus explains that these are payments which effectively pay the employee the income tax impacts of compensation to that employee. (T. 693)

incentives are disallowed, EAI would be required to change its compensation approach, and its employees would no longer share that financial success risk. (T. 1666)

EAI witness McDonald testifies that Staff's and the AG's proposed disallowance appears to be based on the theory that employee incentives tied to stockholder benefit result in the "interests of shareholders and customers ... not (being) in alignment so customers should not pay for all of the cost of these programs." Mr. McDonald asserts that tying of compensation to Entergy corporate earnings and stock prices will encourage employees to increase efficiency and reduce costs, to the benefit of customers; thus, the interests of shareholders are not at odds with those of customers. (T. 153-154) Mr. McDonald testifies further that it is not reasonable to disallow these costs under a "false assumption" that they are not a "reasonable cost of utility operations." (T. 155)

Staff witness Hilton disagrees with Mr. McDonald's equating ratepayer interest with that of Entergy Corp. stockholder interest, acknowledging that cost savings may, to some extent, be shared by ratepayers, but cost cutting to increase financial value can also be at the expense of ratepayers, *e.g.*, reductions in maintenance and repair, which will eventually result in higher rates. (T. 1514) Mr. Hilton asserts that Mr. McDonald ignores this dichotomy of interest, which is why a sharing is appropriate. Mr. Hilton further notes that a rate increase itself is a direct benefit to stockholders at the direct expense of ratepayers, who, unlike customers in a competitive market, cannot simply take their business elsewhere. (T. 1514) Mr. Hilton also testifies that tying these incentives to the financial success of Entergy Corp. rather than the success of EAI increases the disconnect between the payment of the incentive and any EAI ratepayer benefit. Finally, Mr. Hilton testifies that Staff's recommendation is not to simply disallow these costs, but rather "to encourage objectives which yield direct benefits to ratepayers." (T. 1515)

AG witness Marcus questions the validity of EAI witness Gardner's rationale for considering these incentives as simply the cost of doing business, noting that compensation programs tied to surveys of other companies' programs and as employed by EAI, will inevitably become circular and spiral upward. Mr. Marcus rebuts Mr. Gardner's assertions that these incentives, overall, are tied to a combination of factors, stating that several of the incentive packages are tied only to financial performance and all of them have some financial incentive attached. Mr. Marcus also testifies that, in a competitive market, competitive pressures do not automatically allow higher prices as a result of paying these large incentive packages. Because prices cannot be increased, commensurate cost cutting measures must be taken to accommodate the increased expense, including lay offs, outsourcing, or increased efficiency. Absent other expense reductions, the result will be reduced profits and disgruntled stockholders. In contrast, Mr. Marcus continues, for rate regulated firms, which include 100% of these costs in rates as the "cost of doing business", the ratepayer simply pays the increase, receiving no commensurate benefits from cost cutting or increased efficiency. (T. 758)

The Commission finds that, as both witnesses Hilton and Marcus testify, the incentives tied to <u>operating</u> performance do increase efficiency, safety, and reliability and provide direct benefits to ratepayers in the form of better and more reliable service and should be included in rates. The Commission further finds that the incentives tied to <u>financial</u> performance are clearly designed to directly, materially, and measurably increase stockholder value, and provide ratepayer benefit, and should, thus, be shared with stockholders.

The Commission, however, does not find substantive evidence of any material benefit to ratepayers attributable to those programs strictly tied to the stock prices of Entergy Corp. Although EAI witnesses testify to some general benefits ratepayers may enjoy, EAI offers no substantial evidence of ratepayer benefit which would justify including these stock-driven incentives in rates.

The Commission finds that both Staff and the AG recommend some sharing of costs for those programs which contain general financial performance measures, including the Exempt Incentive Plan, Executive Annual Incentive Plan, Management Incentive Plan, and the Team Sharing Incentive Plant. (T. 689-690) The Commission, however, finds that, while the AG recommends a simple 50% sharing of the entire incentives paid under each of these programs (T. 689-690), Staff has more precisely measured those portions of the incentives which should be shared. (T. 1500) The Commission finds that Mr. Hilton has measured the actual percentage of the financial performance measures included in each of the incentive programs, which Mr. Marcus did not do. Therefore, the Commission adopts Staff's proposed adjustments to these four incentive programs as more precise.

The Commission, however, finds that, as discussed by Mr. Marcus, the Long-Term Incentive Plan, the Equity Awards, and the Restricted Share Awards, totaling $1,879,525 (T. 689) as well as EAI's Stock Option Incentive Program, totaling $15, 365,000 (T. 690), "are based entirely on stock price of the parent company." (T. 692)

Having found no direct or measurable benefit to ratepayers of these types of incentives, the Commission directs that these costs not be included in rates.

As to Mr. Marcus' recommendation to disallow certain perquisites provided EAI's Chief Executive Officer and the five top executives at Entergy Corp. which include club dues, financial counseling, the corporate airplane, and a tax "gross-up", the Commission finds no substantial evidence to support the recovery of such expenditures from EAI's ratepayers. The Commission finds that, as noted by Mr. Marcus, these types of expenditures are unreasonable in light of the salaries paid Entergy's top executives. The Commission therefore disallows these perquisites.

Director and Officer Liability Insurance

EAI's application included $191,580[38] in expenses for Director and Officer Liability ("D&O") Insurance. Staff witness Plunkett recommends a 50% sharing of these costs, pursuant to past Commission practice and based on the benefits that D&O insurance provides for both stockholders and ratepayers. (T. 1472) Ms. Plunkett further testifies that her recommendation does not presuppose that this expenditure is unreasonable nor does it imply it is not useful in shielding officers and directors from shareholder litigation. Rather, she continues, her recommendation recognizes that the protection afforded officers and directors is primarily a benefit to shareholders, with EAI providing little evidence of benefits to ratepayers. (T. 1505)

AG witness Marcus, noting similar Commission findings in other dockets, also recommends that these costs be shared equally between shareholders and ratepayers,

[38]Ms. Plunkett removed $95,790 in D&O Insurance from EAI per book, representing 50% of actual expenses. Actual per book expenses would be twice that amount or $191,580.

testifying that the shareholders are the beneficiaries of such policies when mismanagement is the subject of litigation by shareholders. (T. 702, 767)

Mr. McDonald recommends that the Commission reject the Staff's and the AG's proposed adjustment, arguing that the cost is "a reasonable and legitimate cost...to encourage qualified individuals to serve as a member of the board of directors." Mr. McDonald also testifies that the positions taken by Staff and the AG, on this and other similar recommendations would, if carried to every EAI cost, result in leaving EAI without "its legal right to recover the reasonable costs it incurs to provide electric service to its customers." (T. 155)

The Commission agrees that ratepayers, as well as shareholders, benefit from good utility management, which D&O Insurance helps secure. However, as found in prior dockets, the direct monetary benefits of D&O Insurance flow to shareholders as recipients of any payment made under these policies. That monetary protection is not enjoyed by ratepayers. The Commission therefore finds that, because shareholders materially benefit from this insurance, the costs of D&O Insurance should be equally shared between shareholder and ratepayer.[39]

Civic Dues, Donations, and Club Memberships

Both Staff witness Plunkett and AG witness Marcus recommend disallowance of all costs related to civic club dues, club memberships, donations, and other costs such as "institutional advertising, lobbying, and donations, including support and sponsorship of local community organizations and local events." (T. 695.697, 1471) Ms. Plunkett notes that both FERC, which requires these items be listed as non-utility expenses, and this Commission have, for many years, excluded such costs from consideration in rates as unnecessary to the provision of utility service. (T. 1480-1481) Mr. Marcus testifies that various costs he recommends for disallowance constitute activities which are in fact image advertising, charitable donations for which ratepayers should not be responsible and non-utility expenses such as football outings, golf tournaments, and country club dues. (T. 762-763)

Ms. Plunkett and Mr. Marcus each testify that they used sampling techniques in order to quantify the recommended disallowances. (T. 695-697, 764-765, 1471-1472, 1481-1482) Ms. Plunkett testifies that she limited her application to vendors supplied by EAI for review and proposes a total disallowance of $218,798. (T. 1482) Mr. Marcus tested several accounts, which resulted in proposed disallowances in accounts 500, 580, 921, 907-912, and 930.2 based on review of a sample of invoices provided by EAI in response to data requests. Mr. Marcus recommends disallowance of $652,639 in Accounts 907-912, $176,615 in Accounts 500, 580, and 930.2, and $470 in Account 921. (T. 765)

EAI witness Wright testifies that, although the Company did not intend to include country club dues in its rate request, the other costs related to community activities are reasonable, necessary expenses. Mr. Wright asserts that activities at restaurants, country clubs, football games, civic club meetings, and other local gathering places provide EAI the opportunity to build and maintain relationships, increase dialogue, disseminate information, and "recruit assistance...to support Economic Development efforts....". (T. 553-554) Mr. Wright further testifies that, in addition to certain errors

---

[39]Moreover, as discussed earlier, Entergy Corp. has competitive businesses. They also benefit from D&O insurance, and requiring ratepayers to pay the full cost of that insurance would constitute an improper

made by Mr. Marcus in his calculations, the samples used by Staff and the AG were not appropriately drawn. Mr. Wright asserts that the samples had been limited to certain amounts and vendor names and the results should not have been applied against the entire population in the accounts. (T. 555-557) Based on his review and corrections, Mr. Wright concludes that Staff's adjustment should be limited to a disallowance of $68,000 and that of Mr. Marcus to $65,000. (T. 557)

The Commission finds Mr. Wright's justification for ratepayer funding of these various expenses unpersuasive. The expenses include thousands of dollars for:

- football tickets and outings,
- concerts, from the symphony to Kid Rock ,
- cookies, buck knives, and bath products,
- golf balls and golf tournaments, both in and out of state,
- functions and dinners for political figures, both in and out of state,
- hot air balloon championships, and
- liquor.

Such expenditures provide no discernible ratepayer benefit and should be excluded from rates.

Although EAI admits that certain expenses, such as donations and country club dues, should only be included in non-utility accounts, (T. 1769) many of these non-utility expenses were nevertheless included in utility accounts and in EAI's requested rate increase. Because of EAI's failure to account for these costs correctly or to make appropriate corrections or disclosures when filing for a rate increase, the Commission is

subsidy from the regulated portion of Entergy Corp.'s operations to the unregulated.

disinclined to rely on the validity of the records which EAI has provided. The Commission is also disturbed by EAI witness Wright's testimony regarding the sampling employed by Staff and the AG, in which he criticizes Staff's and the AG's use of limited data as applied to the accounts in question and recommends that disallowances be limited only to those invoices each identified as non-utility. (T. 556-557) The Commission finds such testimony especially inappropriate because it was EAI which limited the data available to both, claiming that providing all the requested and needed data would be "burdensome." (T. 765-766, 1482)

The Commission finds that EAI has provided no credible evidence to support their claim that any of these expenses in the accounts are related to the provision of utility service. The Commission further finds that the analysis performed by Staff and especially the analysis performed by the AG provide the best measure upon which the Commission can determine which costs are not utility-related. The Commission notes that EAI had three opportunities in which to put into evidence the exact costs which make up these accounts: (1) when it filed its Application; (2) when it filed its Rebuttal testimony; and (3) when it filed its Sur-surrebuttal testimony. EAI chose not to do so. The Commission, having found Mr. Marcus' examination of these accounts to be thorough despite the limitations imposed upon him by EAI, adopts the AG's total dollar disallowances for purposes of calculation of EAI's revenue requirement.

Affiliate Rules Compliance Costs

AG witness Marcus recommends that the Commission disallow 50% of the costs incurred by EAI to comply with the Commission's Affiliate Transaction Rules. (T. 761) Mr. Marcus testifies that he agrees that such costs are legitimate and needed for the enforcement of affiliate rules created to protect ratepayers from subsidizing non-utility affiliate activity. However, Mr. Marcus also testifies that ratepayers should not be financially harmed by EAI's compliance because such rules, and the costs to comply with them, would not exist if there were no affiliates. (T. 765) Mr. Marcus acknowledges that some of these compliance costs relate to other types of rules, such as FERC's transmission's codes of conduct, which do not directly protect ratepayers from providing subsidy to affiliates. (T. 761) To recognize costs related to these other types of rules, Mr. Marcus recommends that only 50% of compliance costs be disallowed. (T. 761)

Mr. Wright testifies that, irrespective of Mr. Marcus' conclusions, none of these costs would be incurred if it were not for the existence of the Commission-mandated Affiliate Transaction Rules. Mr. Wright testifies that these Rules are enforced entirely upon the regulated utility, that any violation of those rules would result in penalties assessed against the utility alone, and that to disallow these compliance costs would be "unreasonable and could be considered an unlawful confiscation of utility property." (T. 561-N)

The Commission finds that the costs of compliance with the Affiliate Transaction Rules will provide a substantial benefit to ratepayers, especially given the substantial, material cost affiliate abuse by utilities could have on those same ratepayers. The Commission, therefore, rejects the AG's proposed sharing and will allow 100% of these costs to be included in revenue requirement. The Commission, however, reserves the right to revisit this issue, as utilities seek out new corporate configurations and additional affiliate activity in the future.

Industry Organization Dues

EAI witness McDonald recommends the Commission approve 100% of industry dues in the amount of $1,237,426[40] for the Electric Power Research Institute ("EPRI") and Southeastern Electric Exchange ("SEE"), testifying that these organizations benefit EAI and its ratepayers through research and development and sharing of best practices. (T. 113-114) EAI witness Wright recommends that the Commission allow all but $150,502 of the $570,084[41] dues for Nuclear Energy Institute ("NEI"). (T. 561-U) AG witness Marcus indicates EAI has accepted his disallowance of 49% of Edison Electric Institute ("EEI") membership fees (T. 765).[42] Staff witness Plunkett recommends 100% disallowance of these costs, noting the Commission's prior finding that these costs do not provide direct ratepayer benefits. Ms. Plunkett therefore recommends a disallowance of $269,543 for EEI, $15,017 for SEE, $1,222,409 for EPRI, and $70,085 for NEI. (T. 1485) AG witness Marcus has analyzed the expenditures of both NEI and EEI to quantify any activity which provides no direct ratepayer benefit. He concludes that portions of the membership expenses should be disallowed based on his analysis indicating that approximately 49% of EEI activities are promotional or lobbying. Additionally, he testifies that, although his access to NEI records was limited, at least 50% of activities appear to be non-utility related and, thus, recommends a 50% disallowance of NEI membership costs. (T. 699-702, 765-766, 2030)

[40]$1,222,409 EPRI dues plus $15,017 SEE dues. (T. 1485)

[41]AG witness Marcus recommended disallowance of $285,042 representing 50% of all NEI dues, with 100% of NEI dues twice that amount, or $570,084. (T. 561-U)

[42]EAI's currently proposed revenue requirement contains neither disallowance. (T. 168)

The Commission is aware that new technology and possible technological breakthroughs regarding the generation, transmission, and distribution of electric power are being explored by the utility industry. The Commission is concerned that, absent a more affirmative policy position from the Commission, there may be a diminished incentive for utilities to pursue investment in those new technologies - technologies which could provide more efficient utility operation with direct ratepayer benefit.

The Commission seriously considers the testimony as to the numerous benefits EAI and its ratepayers have received because of EAI's membership in various industry organizations. (T. 147-152, 1632-1340, 1720-1722) The Commission also finds that such testimony affirmatively ties certain benefits received to utility operations, although the witnesses have not specifically quantified these individual benefits. EAI's description of the technological advancements which are available through these organizations is persuasive.

Therefore, the Commission finds that membership in EPRI and SEE appear to provide overall benefits, as the organizations' costs are incurred primarily for technological advancement or best practices activities. With regard to NEI and EEI, the Commission is also persuaded that benefits for ratepayers do exist, but that these organizations also heavily participate in certain lobbying and promotional activities which do not provide ratepayer benefits. EAI provides little quantification of those activities which are utility-related and directly benefit ratepayers in contrast to those that do not. Therefore, the Commission, having considered EAI's failure in this regard and in view of the analysis performed by AG witness Marcus (T. 2027-2035), finds Mr.

Marcus' proposed disallowances for both NEI and EEI dues reasonable and supported by the record and adopt them here.

The Commission recognizes that this decision, regarding these costs, represents a departure from prior rulings. While the Commission will allow recovery of these costs at this time, in all future cases, the Commission will require significantly more support than EAI assertions. Therefore, the Commission directs EAI to file, with any future general rate filing or in any request it may make for recovery of these costs, a cost analysis reflecting all benefits it deems it has received over the prior 24 months from any trade organization for which it seeks membership cost recovery. That cost analysis shall quantify each utility-asserted benefit of membership, showing the tie between the organizations' activities and the benefits which are provided directly to ratepayers. EAI shall also file testimony in support of any analysis it provides.

Nuclear Outage Expense

AG witness Marcus testifies that the test year amortization of ANO One Nuclear Refueling costs are greater than the amount expected, based on the latest costs for that refueling. Mr. Marcus recommends that this amortization be adjusted to reflect that more current level. (T. 693-694) EAI witness Wright testifies that the current refueling has been completed and the actual cost amortization based on that current refueling is $21,235,135, which Mr. Marcus accepts. (T. 557, 760) Therefore, the Commission finds this level of ANO One Nuclear Refueling cost amortization appropriate and adopts that amount.

Other Operating Revenues

AG witness Marcus testifies that EAI failed to update its Trip Charge revenues, Reconnect Charge revenues, and Returned Check Charge revenues, all of which experienced fee increases during 2005 and none of which EAI updated in its pro forma year. Mr. Marcus recommends these revenues be updated to reflect expected changes. Mr. Marcus also recommends that interest on Deferred Payment Arrangements be reclassified as utility revenue rather than be considered "below-the-line" or non-utility. Mr. Marcus notes that, under the MBSA, all of the accounts receivable are included in rate base to earn a return. Mr. Marcus states that any Deferred Payment interest reflected in those accounts receivable will also earn a return. Therefore, Mr. Marcus testifies that this small level of service revenues, only $26,000 in 2006, is more appropriately shown as utility revenues. (T. 703-704)

EAI witness Meyer responded by updating his test year revenues for the fee increases. (T. 2567) In his Surrebuttal testimony, Mr. Marcus first testifies that although EAI made certain appropriate adjustments to test year for the fee updates, EAI failed to update for the pro forma year. Mr. Marcus testifies that, as indicated in a data request response from EAI, during the aftermath of Hurricane Katrina, which fell within the test year, EAI extended a moratorium on service shut offs, which resulted in abnormally low revenues for the various revenues at issue. (T. 767-768) Therefore, Mr. Marcus recommends that these accounts be adjusted to a normal, annualized pro forma level, which incorporates the fee increases during the test year, adjusts for lower revenues caused by Katrina, and updates those revenues to reflect expected pro forma levels. In addition, Mr. Marcus testifies that EAI did not respond to his recommendation regarding reclassification of interest revenue on Deferred Payment Arrangements. (T. 703-704, 767-768)

The Commission finds Mr. Marcus' analysis, which incorporates the fee changes with normalized test year data and updates the revenues through the pro forma year, is reasonable and is the best estimate for ratemaking purposes. The Commission also finds reclassification of interest on Deferred Payment Arrangements to above-the-line Account 451 for ratemaking purposes is, as Mr. Marcus testifies, consistent with inclusion of those charges as part of Accounts Receivable, for which EAI earns a return. Therefore, the Commission adopts the AG's pro forma balance for the fee revenues in the amount of $3,977,000 (T. 768) and approves, for rate purposes, reclassification of the interest revenues reflected for the test year on EAI's books to Account 451.

Income Taxes

Conversion from Flow-Through Method to Normalization Method

Staff witness Hilton recommends that EAI be directed to: convert from the Flow-Through Income Tax method it currently employs to the Tax Normalization method, which should reduce income taxes to the ratepayer; calculate its current revenue requirement incorporating that method; and, maintain sufficient records to prospectively verify compliance in this regard. (T. 1502-1503) EAI witness Wright agreed to make this change and filed, with its currently recommended revenue requirement, income tax expense which reflects the Normalization method. Mr. Wright also recommends that the tax method be applied prospectively only. (T. 545-548) Mr. Hilton subsequently incorporated Mr. Wright's calculation into Staff's proposed revenue requirement in his Surrebuttal testimony. (T. 1516-1517) In response, Mr. Wright noted that Staff's tax calculation had incorrectly incorporated certain aspects of EAI's current revenue requirement position rather than its own, and should be adjusted accordingly. (T. 561-V) Mr. Wright testifies further that the appropriate level of income taxes, using the Normalization Method, will be dependent upon the final Commission determinations made in this docket. (T. 561-V)

The Commission, finding no opposition to implementation of Income Tax Normalization and that the change should provide ratepayer benefit, approves that method to be applied prospectively and directs EAI to utilize the method when submitting its compliance revenue requirement and cost of service.

Manufacturing Deduction in Tax Calculation and
Revenue Conversion Factor

Mr. Marcus recommends that the Commission direct EAI to incorporate the manufacturing tax deduction allowed under the American Jobs Creation Act of 2004 ("Jobs Act"). That statute, according to Mr. Marcus, is applicable to EAI's generation function and will allow a deduction of six percent of taxable income for 2006 and, beginning in 2007, a 7% deduction. Mr. Marcus calculates the credit allocating taxable income to generation based on the generation function's overall percent of rate base, using a 6% rate assuming a mid-pro forma year. (T. 712-713) EAI witness Wright testifies that EAI is in agreement with that prospective deduction, (T. 561) and Staff witness Hilton testifies that Staff also supports the deduction's incorporation into revenue requirement using Mr. Marcus' methodology. (T. 1503)

The Commission finds the proposed application of the deduction reasonable and reasonably known and directs EAI to incorporate that deduction into its compliance revenue requirement and cost of service, using the rates and methodology proposed by AG witness Marcus.

Mr. Marcus also recommends that the deduction, which is directly tied to the generation portion of taxable net income, be incorporated into the revenue conversion factor, appropriately reflecting the tax impact of the deduction on incremental revenues. (T. 716-717, 769) Mr. Hilton testifies in support of the deduction and states that Staff appropriately incorporated the deduction into its currently recommended conversion factor. (T. 1503) EAI witness Gillam testifies that the deduction "is not a direct result of a statutory income tax rate..." and, therefore, should not be included in the factor. (T. 2280) Mr. Gillam asserts further that "it is extremely difficult to rigorously quantify a specific tax rate adjustment going forward...due to the expected year by year variability of the tax deduction..." and recommends that the deduction not be included in the revenue conversion factor because it "is not warranted." (T. 2305-2306)

The Commission finds that the deduction is directly tied to incremental taxable income and has the same general effect as that of the state tax rate. The Commission disagrees with Mr. Gillam's assertion that the annual variability of the rate for the deduction limits its applicability here. The Commission sets current revenue requirement, based on the known measurements of revenues and expenses, tax rates, <u>and</u> tax deductions, at one point in time. All of those elements of revenue requirement are subject to significant variability prospectively. As with any of these other revenue requirement elements, then, the prospective variability of the manufacturing rate is irrelevant. The Commission adopts Staff's proposed application of the manufacturing tax deduction as part of EAI's revenue conversion factor in this docket.

RATE SCHEDULE REVENUES

Billing Determinants/Base Rate Revenues Growth Adjustment/Weather Adjustment

EAI witness Meyer testifies that EAI's proposed pro forma billing determinants were established by first determining the individual customer actual monthly usage in 2005 to set as test year, to which EAI then applied a reasonable year end adjustment[43] and a reasonable temperature adjustment to reflect normal weather. (T. 2562) Staff witness Swaim notes that EAI has "proposed pro forma temperature normalized billing determinants[44]...as well as Peak kW demands."[45] In this regard, Mr. Swaim testifies that he verified, through testing, that EAI's proposed test year billing determinants were consistent with those underlying the financial records and revenues in the test year and concluded they were "materially accurate". (T. 2673) Mr. Swaim, however, testifies that significant differences in methods used for the customer growth adjustment and for the weather adjustment exist between Staff and EAI and result in significant differences in total billing determinants and revenues, with EAI proposing approximately $20 million[46] less in revenues. (T. 2679)

Mr. Swaim found EAI's weather adjustment overly complex, relying on hourly temperature data, multiple Heating Degree Day ("HDD") and Cooling Degree Day ("CDD") measures to be applied within each day, and which are "highly correlated to

[43]EAI witness Meyer annualized the last month's usage in the test year to calculate his "growth" adjustment or "year end adjustment". (T. 2560)

[44]Billing determinants include customer counts, kilowatt-hours [kWh], billed kilowatt volumes (kW), and lighting fixture counts. (T. 2670)

[45]KW demand methods addressed include coincident peaks ("CP"), non-coincident peaks ("NCP"), and maximum diversified demands ("MDD").(T. 2670)

[46]Rate Schedule Revenue from Staff Exhibit ARWB-3, ln. 11, of $923,790,000 (T. Ex. 1147) less EAI Rate Schedule Revenue from Exhibit PBG-7, p. 1 of 2, ln 4 of $903,576,000 (T. Ex 903), equals $20,214,000 difference between Staff and EAI.

each other," with the high correlation coupled with adjustments to each class most likely to result in unreasonable results. (T. 2675-2677) To test the reasonableness of EAI's results, Mr. Swaim explains that he applied EAI's method to internal test year revenue projections,[47] known as AGM, to weather adjust pro forma revenue and found that, after adjustment for growth, EAI's pro forma revenues were $20 million less that its own budgeted levels. (T. 2679) He further testifies that the use of AGM for purposes of a reasonableness check is an appropriate method for validation of the results. (T. 2692)

Staff witness Swaim recommends adoption of his calculated billing determinants and resulting revenues, testifying that he has applied the same Commission-approved model from recent cases, which uses five years of monthly data, to set customer base usage, upon which the weather adjustments for HDD and CDD are applied (T. 2679-2681, 2689, footnote 3) and which is also used to measure the expected growth rates. (T. 2689-2690) He further testifies that he tested the results from his billing determinant analysis against those using the AGM and found the comparison reasonable. (T. 2680-2681)

AG witness Marcus testifies that he has estimated expected residential retail determinants, the results of which, although reached using slightly different methods, are comparable to those proposed by Staff. (T. 756)

EAI witness Meyer objects to Staff's use of the AGM which is partially based on older weather models (T. 2562) and objects to Mr. Swaim's calculation of customer base usage to which the growth adjustment is applied, arguing it contains some measure of

[47]The EAI-supplied revenue calculation, Adjusted Gross Margin ("AGM"), is a measurement used by EAI for internal budgeting and reporting. (T. 2679)

weather variance[48] which overstates the adjustment (T. 2564-2565), and testifies that Mr. Swaim's model for growth may have captured the impact of Hurricane Katrina victims influx into EAI service territory. (T. 2565) Mr. Meyer also objects to both Staff's and the AG's reliance on the historical per book billing data for purposes of adjusting for growth, asserting that the adjustment inappropriately extends past the pro forma year and, therefore should not be adopted for setting rates. (T. 2559) EAI witness Wright, however, recommends that, should these billing determinants be approved and because of the extension past the pro forma year, both "additional capacity costs related to the additional sales and increased O&M costs at the June 2007 level should be included." (T. 560)

Responding to criticism of EAI's weather adjustment model, EAI witness Lynch testifies that the model does not display multicollinearity as asserted by Mr. Swaim. Mr. Lynch asserts that, rather, because it applies temperature bands in recognition that usage is not linear with regard to temperature, EAI's model will actually produce a more accurate result. (T. 2513-2515) Mr. Lynch also expresses concern that Staff's model, based on billing months which may lag usage months, inappropriately applies the monthly weather degree day adjustment to the wrong determinants. (T. 2519-2520) Finally, Mr. Lynch addresses certain concerns he has with AG witness Marcus' weather adjustment, but concludes that the Marcus results are not significantly different from those of EAI. (T. 2523)

The Commission finds the test year billing determinants as proposed by EAI and recommended by Staff reasonable and adopts them for this case. (T. 2673) The

---

[48]EAI witness Lynch testifies that Mr. Swaim's use of the lowest usage months to establish his "base" usage does not account for the weather impacts in that month. (T. 2520)

Commission also finds Mr. Swaim's and Mr. Marcus' use of historical billing determinant data in determining appropriate pro forma adjustments an accepted method which is reasonable and produces reasonable results.

The Commission finds that the use of the growth factor calculated based on five years' of historical data and applied to known and measurable billing determinants is an appropriate and accepted method (T. 2688) for purposes of setting rates and differs little from Mr. Meyer's own use of a year-end annualization. Both methods are employed to estimate the expected level of billing determinants which will occur in the future. In this regard, the Commission finds the five year measure of growth impacts, using Mr. Swaim's model, more reasonably measures and more accurately reflects expected growth than does EAI's method, which takes the customer count from one isolated month and simply multiplies it by twelve. In this regard, the Commission also finds that its adoption of Mr. Swaim's growth adjustment results in no need to further amend either capacity cost or O&M expenses as proposed by Mr. Wright. EAI has filed a fully developed revenue requirement which extends to the end of the pro forma year. Use of known data through the end of the pro forma year will effectively capture any cost changes which are expected to be incurred and for which Mr. Wright expresses concern. The Commission finds, rather, that, when utilizing a pro forma year to capture expected cost increases, had billing determinants not been appropriately updated, a mismatch would have occurred.

The Commission also finds that the weather adjustment applied by Mr. Swaim is reasonable and reflects prior Commission-accepted practice[49] and is adopted here.

[49]Dockets for which Staff witness Swaim's methodologies have been approved by the Commission include Docket Nos. 01-243-U, 02-024-U, 02-227-U, 04-121-U, 04-176-U, and 05-006-U. (T. 2695, footnote 8)

Therefore, the Commission finds that Staff's billing determinants have been calculated using standard practices accepted by this Commission in prior dockets. The Commission finds that Staff's methods will more accurately reflect the expected levels of billing determinants than those proposed by EAI and will thus more accurately and more appropriately reflect expected revenues than EAI's. The Commission finds that the AG's proposed level of billing determinants and resulting revenues support Staff's results, but, in view of the methodology differences, between Staff and the AG, the AG's billing determinants should not be adopted. Therefore, the Commission adopts Staff's proposed billing determinants and rate schedule revenues in their entirety.

Cost of Service

Demand Allocation Method - Production and Transmission

Production Demand Allocations

A significant component of the overall revenue requirement is the fixed costs of production. These are generally associated with the capital costs, return and depreciation of EAI'S generating plants. Because these costs are not directly assignable to customer classes, they must be allocated to the individual classes. The appropriate allocation method is not susceptible to precise "slide-rule type determination," but is a matter of informed judgment.

There are three different proposals as to the issue of the allocation of demand-related costs that are functionalized to production among EAI's retail classes. EAI witnesses Gilliam and Meyer, Staff witness Bradley, and AG witness Marcus all support the Average and Peak ("AP") method. AEEC witness Falkenberg and Federal Agency witness Blank support the 1 Coincident Peak ("1 CP") method. Kroger witness Higgins recommends the Average and Excess ("AE") Method.

The AP method considers both average energy usage and peak usage in the determination of each rate class's allocation of production demand costs. The formula for allocation to each class is:

[(Company Load Factor) X (Class % Contribution to Average Demand)]

+ [(1- Company Load Factor) X (Class % Contribution to Peak)]

where:

Average Demand = Energy Usage/8760 hours and

Company Load Factor = Company Average Demand/Company Peak Demand.

The 1 CP method allocates production demand costs to each class based on its contribution to the Company's peak usage in the 1 hour of the year.

The AE method utilizes each class's Non-Coincident Peaks ("NCP") and energy usage in developing allocations:

[(Company Load Factor) X (Class % Contribution to Average Demand)]

+ [(1- Company Load Factor) X (Class % Contribution to Excess Demand)]

where Excess Demand for each class is the proportion of the difference between the sum of all class's NCP and the Company's Average Demand.

It is important to recognize that the determination of allocations in ratemaking is an art, not a science. A primary goal should be to allocate costs on cost-allocation principles; that is, costs should be assigned to those customers or customer classes that caused the costs to be incurred. A corollary to that principle is that costs should be assigned to the customer or class of customers who enjoy the benefits created by the incurrence of those costs. However, in allocating long-lived assets such as production plant it is nearly impossible to rely solely on cost-causation principles. For example, in the time since the construction of a coal or nuclear plant, many customers for which the plant was built are no longer in the service territory. Further, a utility has a continual influx of new customers for which the plant was not necessarily built.

Perhaps it could be argued that the plant was built based upon projections of customer growth, customer usage growth, and class growth over time. For example, a nuclear unit may have been built in 1980 premised on projections of customers and customer usage through the year 2005. However, that approach is not viable since forecasts are unreliable, and become more so as they move further into the future. Additionally, in many prior cases there were no forecasts of usage twenty-five years into the future.

Regulators generally rely on the usage patterns of current customer classes to develop appropriate allocation factors for the costs of long-lived assets, such as production plant. This is appropriate for two reasons: (1) current customer class usage patterns may reasonably approximate usage patterns in the past; and (2) current usage patterns may be a reasonable basis for determining the current *benefits* that each class receives for production plant. Consequently this Commission considers a blend of the cost-causation principle and the benefits-received principle as a reasonable foundation to develop class allocation factors.

Given those two underlying principles, the Commission will use the AP method for allocating production demand costs among EAI's customer classes for the following three reasons:

(1) The AP method reflects the fact that production plant is built to serve load and provide reliability for 8,760 hours in the year ("Capacity Utilization");

(2) The AP method reflects the fact that much of EAI's production plant was built to provide fuel savings; and

(3) The AP method reflects the fact that much of EAI's production plant was built to provide fuel diversity.

It is also important to note that the Staff has recommended use of the AP Method in EAI's last two rate cases (Docket Nos. 84-249-U and 96-360-U).

The capacity utilization aspect of the AP method is illustrated by EAI witness Meyer. This shows how intensively the capacity is used in each hour of the year. (T. 2575-2578). Further, the fuel savings and fuel diversity aspects of the AP method are discussed by Staff witness Bradley and AG witness Marcus. (T. 720, 770, and 3275) Ms. Bradley states: "The Average and Peak methodology appropriately recognizes that system operations, fuel costs, and fuel diversity are major determinants of generation capacity planning and as such, energy consumption as well as demand are considered in the development of the customer class allocation factors." (T. 3275)

Kroger witness Higgins argues that the AP method results in "double-counting". (T. 989-991) Mr. Meyer provides an example to rebut the double-counting argument made by Mr. Higgins. (T. 2575-2578) However, the Commission disagrees. Mr. Higgins commits a fundamental error in his analysis on this point. He posits that all of the incremental capacity above the system average load that is required for peak conditions is solely attributable to one class ("Peaky Class"). Consequently, he implies that that incremental capacity should be directly assigned to the Peaky Class. That is not correct. During peak hours it is impossible to say that a particular class is causing incremental load. All classes are causing that peak load in proportion to their demands during the peak period.

Mr. Higgins' example also fails to properly note that the AP method is a capacity utilization method and by definition does not double-count. (T. 989-991) Instead, the AP method is a two-step process. First, each time period is considered separately and is given weight proportional to that time period's proportion of total load (capacity utilization). Second, each class's contribution to load in each time period is weighted by that time period's weight and then summed. In the context of Mr. Higgins example (T. 989-991), July has a weight of 11.67% (1,400/12,000), the Peaky Class share of that 11.67% is given as 900/1,400, and the Flat Class's Share is given as 500/1,400. Similar calculations are done for the other months, the July capacity utilization factor of 11.67% is not used again for the other months' calculations, and hence there is no double-counting.

AEEC witness Falkenberg alleges that the AP method is flawed because, as one class's load changes in the off-peak period, the AP method will automatically change the other class's allocation. (T. 1960-1964, T. Ex. 846-850) Mr. Falkenberg accomplishes this through an artificial construction of an example with two 100% load factor customers.

However, the problem Mr. Falkenberg presents is present in all allocation methods, and cannot be maneuvered around or through. In particular, if one customer class's peak usage changes, the other customer's allocation would automatically change.

In the context of his example, assume two customers, with 100% load factors, 100 MW of load each, and $20 million in production fixed costs. Under either 1 CP or AP, each customer would be allocated $10 million in production costs. He assumes a change in Customer A's off-peak load, with corresponding changes in Customer B's allocation of $20 million, to attempt to impugn the AP method.

Instead, let us assume a decrease of 20 MW in Customer A's usage at the peak. Under the 1 CP method, Customer B, who has not changed usage during either the peak or off-peak, is now allocated $11.11 million automatically because of usage of the 1 CP.[50]

Neither the above example nor Mr. Falkenberg's example illustrates a fundamental flaw with either of the two methods. As discussed above, as usage changes in all customer classes, any allocation method that uses current data will result in class allocation percentages that are different than what would be obtained at the time the generating plant is built. All allocation methods proposed in this case use current data, and avoid the laborious and unnecessary process of vintaging plant allocations, *i.e.*, matching up different allocations with the years that the different units were built.

For simplicity, and in recognition that allocation is not an exact science but is based on informed judgment, utility regulators use allocations from current data as a reasonable approximation of any such complicated "vintaging" of different generating units. Further, current data more appropriately matches up costs and benefits.

Additionally, the AP method appropriately reflects the fact that EAI's baseload coal and nuclear plant, which comprise the vast majority of production demand costs, were built to provide both fuel savings and fuel diversity. The average demand

---

[50]Calculated as [100 MW/180 MW] X $20 million = $11.11 million.

component used in the AP method properly weights the fuel savings and fuel diversity benefits in making the AP-based cost allocations.

It is important to point out that fuel savings and fuel diversity are two separate concepts. Fuel savings refers to expected decreases in fuel costs paid by ratepayers because of the substitution of relatively low cost coal and nuclear fuel for higher priced natural gas and oil. Fuel diversity refers to the expected decrease in the variability of overall fuel costs because of the availability of a wide variety of plants using different fuels. This provides a benefit to customers, who prefer less volatility even if there is no expected decrease in overall costs associated with the expanded portfolio of plants. This benefit is analogous to the benefits of diversification of common stock in a portfolio of common stocks, which is well-established in financial theory.

During the late 1970's and early 1980's EAI completed its plan of adding a number of coal and nuclear plants to its generation portfolio for the benefit of EAI's customers. While those plants were built with a goal of meeting future peak demand, fuel savings and fuel diversity were important goals as well.

AEEC witness Falkenberg argues that the justification for EAI's relatively expensive baseload plant was not even partially based upon a desire to provide fuel savings. (T. 1966-1976) This is not correct. It is clear that, especially for EAI's nuclear plants, potential fuel savings was an important factor in the decisions leading to the construction of those plants. The fuel savings from EAI's Arkansas Nuclear One units vastly exceed its fixed costs, which inured to the benefit of high load factor industrial customers. Even in the case of the uneconomical Grand Gulf nuclear plant, significant fuel savings have inured to the benefit of EAI's high load factor customers. From cost-causation and benefits-received perspectives, because of the significant fuel savings associated with EAI's nuclear and coal units, the AP method's inclusion of average demand in the calculations is appropriate.

Additionally, EAI's baseload plants were built to provide fuel diversity. As discussed earlier, fuel diversity is a different concept than fuel savings. Fuel diversity also disproportionately benefits high-load factor customers. At the time EAI's nuclear and coal units were planned and constructed, the Entergy system and EAI were primarily dependent upon natural gas and oil-fired plants. A rationale for the building of the nuclear and coal units was to provide fuel diversity. From both the cost-causation and the benefits-received perspectives, the AP method's inclusion of average demand in the calculations is appropriate because of the significant fuel diversity associated with EAI's nuclear and coal units.

Consequently, the Commission finds that the AP method should be used to allocate production demand costs among EAI's retail rate classes in this case. We reject the 1 CP method since it only considers 1 hour out of 8,760 hours during the test year and does not consider the benefits of fuel savings and fuel diversity associated with EAI's nuclear and coal units. The Commission also rejects the AE method because consideration of non-coincident peaks has little bearing in cost-causation for production plant. The Federal Agencies' proposal to use minimum base usage instead of average energy usage is flawed because it does not adequately reflect all of the fuel savings and fuel diversity benefits of EAI's baseload plant. Mr. Falkenberg also proposes an alternative AP method based upon one in the 1992 National Association of Regulatory Commissioners ("NARUC") Cost Allocation Manual at page 57. (T. 1832-1833) However, that particular method is flawed because, instead of using the system load factor for weighting purposes, it uses a factor that artificially inflates the portion of fixed costs that are considered "demand-related".

Transmission Demand Allocations

EAI, Staff, the AG, and the Commercial Group recommend or accept the use of the 12 Coincident Peak ("12 CP") method to allocate transmission demand costs. (T. 2540, 2580-2581, 2608, 3300-3301, 720, 772) AEEC and the Federal Agencies support the use of the 1 CP method to allocate transmission demand costs. (T. 1831, 1977, 1066-1069)

The parties that support the 12 CP method argue that it: reasonably reflects the mix of customers' respective electrical load characteristics and the relative costs to serve such loads throughout the year; considers the need for stable levels of reliability throughout the year; and reflects that transmission is connected to generation. Additionally, they point out that baseload generation requires more generation than peaking facilities, and that the 12 CP method is used by the FERC to allocate transmission costs. (T. 772, 2539, 3300-3301)

The parties that support the 1 CP method state that the transmission system was sized built to serve the single system peak and that, although the 12 CP method may be appropriate at the wholesale level, it would not be inconsistent to allocate transmission demand costs among EAI's retail classes using the 1 CP method. (T. 1066-1068, 1831)

The Commission agrees with the arguments in support of the 12 CP method as applied to the retail wholesale allocation and the retail rate class allocations and adopts that methodology.

Customer Service and Information Expenses

With regard to Accounts 907, 908, and 910, Customer Service and Information expenses, Mr. Marcus, based on his review of the items contained in this account, recommends that the Commission allocate these on the same basis as EAI has allocated its sales and marketing expenses. (T. 722) Mr. Marcus testifies that these accounts reflect very specific expenses related entirely to large classes or are other costs, which were listed as "economic development", but relate to civic club and charitable activities and communicating with community leaders regarding energy matters. Mr. Marcus, therefore, concludes that assigning 84% of those costs to residential customers is not appropriate. Mr. Marcus states that, while EAI witness Gillam did adjust certain accounts, the majority of information he has reviewed indicates that a customer count allocation is not appropriate, with large customers receiving almost none of these costs, and recommends that the Commission approve an allocation which reduces the "extent to which residential customers subsidize these activities." (T. 775). Mr. Gillam testifies that EAI has followed the appropriate accounting as required by the NARUC Electric Utility Cost Allocation Manual which requires that these costs be deemed "customer-related." Mr. Gilliam, therefore, applied the allocation factor which is based on "customer count", is wholly appropriate, and should be adopted. (T. 306-307)

The Commission finds that Mr. Marcus' proposal to set an allocation factor, which fairly allocates these costs based on the makeup of the "customer related" costs EAI posts to these accounts, is appropriate. The Commission finds that EAI's policy to recognize these costs as "customer related" as required by NARUC guidelines was also appropriate, as was its initial assignment of customer count as a basis to allocate these costs. However, the Commission also finds that, in view of the analysis provided by Mr. Marcus, the actual expenditures reflect that the "customer-count" allocation would not be appropriate. Many of these costs appear to directly benefit commercial and industrial customers. (T. 773-774) Mr. Marcus' recommendation is to use a "broad based" allocation factor and proposes the Commission adopt the "total utility plant" allocator. The Commission finds this change will result in a more fair allocation of these costs and, thus, adopts it here.

Miscellaneous Service Revenues Allocation

AG witness Marcus testifies that his analysis of the Rate Schedule 29 revenues contained in "Account 451 (other than EAI's adjustments from AJ01 and AJ04) are paid (almost entirely, some 95%) by residential customers... (and are related to)...trip charges and reconnections associated with non-payment and costs of returned checks." (T. 722-723) Mr. Marcus recommends that these revenues be allocated "using the retail customer accounting costs excluding uncollectibles, with no allocation to wholesale... (which would) assign 80% of the revenues to the residential class, generally commensurate with the underlying costs." (T. 723) EAI witness Gillam amended EAI's original filing to reflect certain re-allocations but also states that "(d)ue to the general nature of these revenues, it is appropriate to allocate them based on the total revenue requirement for the Arkansas retail jurisdiction." (T. 2282) Mr. Gillam also testifies that "(t)o do otherwise, would require a level of analytical time and effort that is not warranted give the materiality of the revenue involved." (T. 2307) AG witness Marcus, however, asserts these revenues are not "general", are paid predominantly by residential customers for specific services, and should be allocated as he recommends. (T. 775)

The Commission finds that the evidence indicates the appropriate allocation of the revenues should, as Mr. Marcus points out, follow the costs associated with their generation. The Commission also notes that the "analytical time and effort" appears to have been already expended by Mr. Marcus in this regard, having identified the makeup of the revenues and makes his recommendation based on that effort. Therefore, the Commission adopts the allocation as proposed by the AG.

Storm Damage Reserve Allocation

AG witness Marcus testifies that, according to EAI witness Wright, approximately 62% of the Storm Reserve is production related. However, Mr. Marcus points out that the Storm Reserve and its related costs are allocated using only transmission and distribution factors and therefore had requested that EAI provide clarification. (T. 752-753) The Commission finds that, because it adopts no balance for the Reserve, the allocation issue will relate only to the Storm Damage expense. The Commission finds that the functional makeup of the allowed expense should dictate its allocation to class. Therefore, the Commission directs EAI to allocate the expense based on the factor which most closely reflects the functional cost incurrence of those costs used in the calculation of the Commission adopted normal expected Storm Repair Expense of $14,449,000. The Commission also directs Staff to review the subsequent allocation EAI incorporates into its compliance filing and report its determination to the Commission at that time.

Rate Design

Large General Service Time-of-Use Class ("LGSTOU") and
Large Power Service Time-of-Use Class ("LPSTOU")

Combine Classes

Staff witness Bradley testifies that EAI proposes combining the two large time-of-use ("TOU") classes, Large General Service TOU, or LGSTOU, and Large Power Service TOU, or LPSTOU, into one class. Ms. Bradley recommends that, in view of the significant adverse rate impact to LGSTOU customers, the Commission should reject this proposal or, in the alternative, require a rate design which would mitigate the inter-class impact. (T. 3278, 3306) EAI witness Meyer testifies that the impact, for which Ms. Bradley expresses her concern, was related to an isolated customer, whose pattern of consumption resulted in a significant percentage increase. In this regard, Mr. Meyer also points out that, for almost 95% of LGSTOU customers, the impact is less than or equal to only 16%. Mr. Meyer states that EAI proposed merging these schedules because of the confusion regarding rate design for LGSTOU customers as they exceed the maximum demand and become eligible for LPSTOU service. Mr. Meyer continues to recommend combining these classes, but, should the Commission not wish to combine them, he recommends that each class maintain "their respective rate structure by increasing each pricing component by the same percentage increase." (T. 2582-2583)

The Commission finds a 16% shift significant and that, as large and presumably sophisticated customers, any confusion the LGSTOU customers experience does not warrant that shift. The Commission, therefore, adopts Staff's recommendation to keep these two classes separate. The Commission, however, adopts EAI's suggestion to maintain the current rate structure.

Residential Rate Block Structure, Residential Water Heating, Commercial Water Heating

AG witness Marcus recommends certain changes to rate design for residential customers and for commercial customers. Mr. Marcus testifies, first, that EAI proposes no changes be made to the current residential block structure and that any increases be assigned to each declining block in the same proportion currently reflected in rates. Mr. Marcus testifies that, because of the AG's long-term policy to encourage conservation and increased efficiency through use of natural gas, it is his proposal that fixed charges be minimized and block rates be designed on an inverted basis for residential customers. (T. 726-729) Mr. Marcus recommends that, to minimize any sudden rate impact, a gradual change in design to a "flat or inverted summer rate, a lower flat winter rate, and limited reliance on customer charges" should be implemented, the result of which should be that weather sensitive customers, who contribute to the winter peak, will be required to pay the higher cost they incur. (T. 727)

Mr. Marcus also recommends that the Commission close to all new customers the promotional rate RW residential water heater tariff and the Rider M14 commercial customer water heater tariff, testifying that the subsidized service is wasteful and promotes inefficiency. Mr. Marcus recommends that the Commission consider similarly closing the winter rate to new customers and replacing it with a flat rate. (T. 730) Mr. Marcus asserts that EAI relies upon findings made in 1992 as a basis for opposition to his proposed changes and that such findings are no longer valid. Mr. Marcus testifies that there have been changes since 1992 that include considerably higher gas costs, with the resulting increase in EAI's marginal costs, thus, making his rate design more economic, and the increasing understanding of costs related to greenhouse gases. (T. 776-779)

Staff witness Bradley testifies that she does not oppose the AG's proposals, conceptually; however, she recommends that "(a)ny significant changes to rate design must take into consideration customer impact." (T. 33053)

EAI witness Meyer opposes Mr. Marcus' rate design changes, asserting that Mr. Marcus provides no analysis to support a change to inverted block rates nor does Mr. Marcus provide analysis to support his assertion that the current water heating and winter tail block rates are not cost justified. Additionally, Mr. Meyer testifies that the Commission has already reviewed and approved the current promotional rate structure in Docket No.90-205-R and that these rates were not at issue in EAI's last rate case. (T. 2589-2590) Mr. Meyer recommends the Commission reject these proposals as not cost justified. (T. 2590)

The Commission finds that the current rate filing is not the appropriate docket in which to raise issues related to conservation and efficiency and effecting these standards through significant changes in rate block design. The impact of the design changes Mr. Marcus proposes should be more carefully considered in a separate proceeding, with customer rate and overall bill impact measured, as well as determining what the resulting revenue impact will be. Therefore, the Commission rejects, for now, the AG's rate design changes regarding the current block structure. The Commission anticipates investigating these rate design proposals within the context of the Commission Docket No. 06-004-R, regarding conservation and efficiency.

However, the Commission is persuaded by Mr. Marcus that changes since 1992 in gas cost and the increasing understanding of the environmental costs of greenhouse gases have rendered the promotional water heater tariffs no longer appropriately efficient or cost effective as Mr. Marcus asserts. (T. 777) The Commission, therefore, adopts Mr. Marcus' proposal to eliminate the RW tariff and the commercial Rider M14, with the proviso that current customers, at their current locations, will be grandfathered under the tariff and may continue service until such time that these customers change location.

In keeping with his proposals regarding the redesign of block rates, Mr. Marcus also proposes that, for any rate decrease, the entire decrease be applied to the first block of energy charges for both summer and winter rates and, for any rate increase, that it be applied to the tail-block, with no change made to the current customer charge. (T. 730) EAI witness Meyer opposes freezing the customer charge should a rate increase be warranted, citing the results of its cost of service which indicates, from a cost-based perspective, that an increase in the customer charge rate from the current $7.73 to $13.52 should be made. (T. 2590)

Given its prior determination with regard to the AG's proposed changes in rate block structure, as well as the import of maintaining rates which are cost-based, the Commission rejects the specific adjustments Mr. Marcus proposes and adopts EAI's proposed design.

Rate Increase Assignment to Each Rate Class

Kroger witness Higgins recommends that EAI's proposed revenue increase be allocated to rate class using "the midpoint of the Energy & Peak and Average & Excess

Demand cost of service results, adjusted for incremental credits for additional facilities and standby services charges" and he provides a table which shows the percentage increase by class this method would provide. (T. 1003) EAI witness Meyer opposes Mr. Higgins' proposed variance from cost based rates, which will be reflected in the final Commission approved cost of service. (T. 2587)

Commercial Group witness Gregory recommends that any rate increase be assigned to a lesser degree to those customers which currently reflect a higher rate of return. (T. 605) In responding to Mr. Gregory's recommendation, Mr. Meyer testifies that, as he understands that proposal, it should move rate classes closer to cost of service and, therefore, he agrees it is appropriate. (T. 2588)

The Commission finds that, in keeping with its prior determinations, increases or decreases in rates should, for the most part,[51] reflect the overall cost of service. In this regard, Kroger witness Higgins' application of his allocation method in assigning increases is not appropriate and is rejected. The Commission finds, in this case, that the overall results reflected by both Staff and EAI are reasonable. The Commission therefore adopts the cost of service method as approved herein, subject to further findings should the newly run cost of service results reflect unreasonable variations from the results reflected in the record.

Tariffs and Riders

Energy Cost Recovery Rider ("ECR")

All parties agree that continuation of EAI's Energy Cost Recovery rider ("ECR") for fuel and purchased energy costs is appropriate. However, parties recommend various

[51]The Commission may find that results of an appropriately allocated cost of service do not reflect reasonable increases or decreases among the classes.

modifications to it. Subject to the limitation and conditions set forth hereinafter, the Commission agrees that the ECR should continue but that certain modifications are necessary.

EAI witness McDonald testifies that the ECR should include the EAI retail portion of the FERC-ordered bandwidth payments associated with "rough production cost equalization" among the Entergy Operating Companies. (T. 101) Mr. McDonald states that the dollars associated with those payments will flow through Service Schedule MSS-3, Exchange of Electric Energy, pursuant to the FERC's order. However, Mr. McDonald testifies that acceptable alternatives to including these payments in the ECR are a new exact recovery rider, the Production Cost Allocation ("PCA") rider, or inclusion of the payments in base rates. (T. 101)

Staff witness Smith argues that it is inappropriate to use the ECR to recover the costs associated with the FERC decision since the ECR was designed to recover net fuel and purchased energy expenses. (T. 2403/16) Kroger witness Higgins opposes EAI's ECR approach because the charges are the result of a federal mandate and not part of the normal conduct of business, and because the ECR is a straight kilowatt-hour charge while the FERC-imposed bandwidth payments reflect a blend of energy costs and fixed production costs. (T. 985-986) Similarly, AEEC witness Falkenberg agrees with the parties arguing that the bandwidth payments should not be included in the ECR. (T. 1942) However, Mr. Falkenberg also proposes that the ECR be merged with the CM rider proposed by EAI. (T. 1853-1856)

The Commission is not persuaded by the ECR approach advocated by EAI. The Commission agrees with the Staff and other parties that the costs associated with the

FERC-ordered bandwidth payments should, as limited and conditioned hereinafter, not be recovered through the ECR. Instead, these FERC-ordered payments should be recovered in a separate rider such as the PCA. Mr. Falkenberg's recommendations will be discussed elsewhere in this Order.

Staff witness Smith also recommends that the retail ratepayers of EAI should receive through the ECR, as an offset to fuel and purchased energy costs, a portion of any revenues received by the Company as compensation for using SO_2 emission allowances in the production of energy. Mr. Smith states that this compensation should be credited to ratepayers through the ECR Rider and the compensation should include SO_2 rider revenue received through System Schedule MSS-3 and SO_2 adder revenue related to off-system sales.

Mr. Smith also testifies that the retail portion of proceeds received by EAI for the Environmental Protection Agency ("EPA") auction should be credited to ratepayers through the ECR. In addition, Mr. Smith states that, if EAI sells allowances in the market or to other EOCs in the future, those proceeds should be credited to ratepayers through the ECR. To comprehend these proposals in this case, Mr. Smith proposes that the test-year amounts of these proceeds be removed from EAI's cost of service and included in the ECR. (T. 2403/14-2403/15) AEEC witness Falkenberg agrees with Staff's proposal and notes that, because the revenues from SO_2 emission sales are volatile and are the subject of a current complaint before the FERC by the Louisiana Public Service Commission, these proceeds should be included in the ECR. (T. 1858-1859, T. Ex. 769-771)

EAI agrees with the Staff's proposed treatment of SO2 revenues but expands it. EAI asserts that, in the future, compliance with a number of environmental regulations will require the purchase of NOx, mercury, activated carbon purchases related to mercury reduction emissions, and limestone purchases related to SO2 compliance. For this reason, EAI witness Gilliam recommends that the ECR should be revised to also include the future costs to the Company of obtaining the necessary allowances. (T. 2298-2299, 2311-2312) EAI witness Castleberry testifies that the costs associated with emission credits and compliance with environmental regulations are volatile and will vary with the amount of coal burned. (T. 1618-1619)

Staff opposes this expansion of the ECR because EAI has not shown that: (1) it has incurred any such costs during the test year; (2) the costs of compliance would exhibit extreme volatility and unpredictability; or (3) recovery of these costs in base rates in a future rate case would not be appropriate. (T. 2403/48)

The Commission concurs with the recommendation of Staff and AEEC on this issue. EAI is directed to include revenues associated with the sale of SO^2 emission allowances in the ECR rider. The inclusion of the other environmental costs in the ECR is not appropriate for the reasons articulated by Staff. However, since these costs have not been incurred during the test year and are not projected to be incurred until the years 2009-13, EAI may seek inclusion of those costs in the ECR at a future date closer to the time when they occur.

Turning to the issue of the appropriate carrying cost to apply to deferred fuel balances in the ECR, Staff witness Smith proposes that the carrying costs be changed from the rate of return approved for EAI by the Commission in a non-appealable final order to the annual Commission-approved rate of interest on customer deposits. Mr. Smith makes several arguments to support Staff's position. First, Mr. Smith argues that provision of the ECR is discretionary and that the ECR provides a fair balancing of interests, even without carrying charges on any over- or under-recovered balances. Second, the true-up provision in the ECR lowers the risk of EAI under-collecting. Third, the recovery of the deferred fuel balance is not long-term in nature, but instead it is recovered through a surcharge over a projected twelve month period. Finally, Mr. Smith states that the Commission has used the same approach for determining carrying charges for Arkansas' gas distribution utilities. (T. 2403/17-2403/21)

EAI witness Gillam disagrees with Mr. Smith's proposed change in the carrying charge rate and states that the Company essentially finances the under-recovery of fuel and purchased power expense, so that the proper rate of return here is the Company's cost of money. (T. 2297)

Staff is correct regarding the appropriate carrying charge. The Commission adopts Staff's position that the carrying charge rate on the ECR should be changed to the Commission-approved customer deposit interest rate for the reasons provided by Staff. The Commission also agrees with Staff and emphasizes that the ECR is a discretionary tariff and that the new carrying charge is symmetric and fair since it applies to both under- and over-recoveries; that is, if the Company over-recovers, the interest rate that customers receive on that over-recovery is the customer deposit interest rate as well.

AEEC witness Falkenberg argues that the ECR, in addition to the proposed Riders CM and PCA, should be seasonally differentiated and voltage adjusted by customer class. (T. 1859-1861) The results of both of Mr. Falkenberg's proposals would be to assign more costs to the residential class and less costs to the industrial class.

EAI, Staff, and the AG oppose AEEC's proposed modifications. (T. 2299-2300, 779-781) AG witness Marcus states that the marginal energy costs are similar during the summer and winter seasons for EAI and that a pronounced summer-winter differential would send the wrong price signals to customers. Staff and EAI witnesses state that the current non-seasonally differentiated ECR rider: (1) provides for levelized annual fuel cost; (2) protects customers from unnecessarily high electric bills in the summer months; and (3) would be undesirable for most customers, particularly commercial and industrial customers. Regarding the proposal on voltage adjusted rates, EAI witness Gillam states that "as a result of M1 discounts, customers taking service at primary and transmission have reduced billing determinants." (T. 2300)

For the reasons stated by EAI, Staff, and AG, the Commission rejects AEEC's proposal to modify the ECR rider for seasonal or voltage differences.

AEEC witness Falkenberg also recommends that Staff conduct an annual audit of the ECR rider. (T. 816) Staff witness Smith disagrees with this recommendation and states that Staff already reviews the ECR filings for mathematical accuracy and periodically conducts verification testing. Mr. Smith states that a requirement for an annual audit could result in a less than optimal use of Staff's limited resources. Mr. Smith states that ECR audits are best left to the discretion of Staff and the Commission. (T. 2403/48-2403/49)

Staff is correct. The timing of audits of the ECR is best left to the discretion of the Staff and Commission. A requirement for an annual audit of the ECR will not be adopted.

Staff witness Smith recommends that EAI provide the Commission with an annual report addressing fuel and purchased energy issues with its annual ECR Rider filing. Mr. Smith states that the report should, at a minimum, include eleven detailed items. Mr. Smith asserts that such a report would be useful to the Commission: (1) power markets have become much more complex and volatile than they were in the past; (2) fuel costs represent a significant portion of EAI's costs; and (3) these costs are collected through an automatic adjustment clause. (T. 2403/22-2403/23) In view of EAI's Rebuttal Testimony, Mr. Smith modified his recommendations. (T. 2403-44)

EAI agreed with Staff's reporting proposals and supports one of the modifications proposed by Mr. Smith. However, the Company does not support one item in Staff's modified reporting proposal that would require EAI to "identify when Units are being run out of economic dispatch because of transmission constraints or other factors, identify and explain the factors affecting such dispatch, and quantify and explain the associated impact on EAI's fuel and purchased energy costs." (T. 2403/44) EAI's concern with this reporting item is that it is not developed in coordination with the annual update cycle for Rider ECR. Further, the scenario of an economic dispatch with no transmission constraints represents an unrealistic situation that can never be achieved. As an alternative, EAI suggests that the Company provide the impact on EAI's fuel and purchased power costs associated with atypical events on Entergy's generation and transmission system when units need to run out of merit order.

The Commission agrees with Staff's recommendations regarding the development of an additional report to be included in the Company's annual ECR filing and directs that such report be filed. This report shall include the items as modified by Staff.

Capacity Management Rider ("CM")

In this case EAI proposes two new riders, a Capacity Management ("CM") rider and a Production Cost Allocation ("PCA") rider. The CM rider would permit EAI to recover, or credit, the APSC retail jurisdiction's share of cost changes associated with a variety of capacity-related costs. (T. 2265-2270) The cost changes recovered through this rider would reflect the incremental revenue requirement of capacity costs not recovered in base rates. Under the proposal, these costs would fall into five categories:

(A) Acquired capacity costs associated with EAI's ownership of additional generating capacity;

(B) Purchased capacity costs associated with the capacity cost component of purchased power costs;

(C) Reserve equalization costs associated with changes in the levels of Service Schedule MSS-1 of the Entergy System Agreement;

(D) Deferred capacity costs which are capacity costs deferred by order of this Commission and the balance of which will be recovered and amortized over twelve months; and

(E) Imputed debt cost associated with increased financial risk from fixed components in purchased power contracts.

EAI proposes that the costs included in this rider would be prospective only, with no true-up, and would be re-determined annually. There would be an annual review in which Staff would have approximately three weeks following EAI's submission to review the calculations. After Staff completes its review and corrections of any errors identified by Staff are made, the annually re-determined rates would go into effect automatically, without an explicit Commission Order. (T. 2265-2270)

The Company makes a number of arguments in support of rider CM. First, EAI notes that, in the future, it will need to acquire additional generating resources to meet its resource planning objectives. The Company does not own or control enough generation to meet the planning criterion that it must control an amount of generating resources that is at least equal to projected peak plus reserves. Further, in order to have a balanced generation portfolio, EAI asserts that it will need to acquire load-following capability in the next few years. Company witnesses have testified that EAI will need to acquire additional generating resources. EAI indicates that it needs to purchase 1,462 MW of capacity in 2007, which will increase to 1,818 MW by 2012. (T. 100, 2331-2333)

EAI testifies that the CM rider would provide EAI with a maximum level of flexibility to act in its customers' interests in contracting for secure power supplies while simultaneously feeling confident that it will receive fair financial recovery for its prudent actions. (T. 97-100, 250)

EAI witness Fetter asserts that credit rating firms, such as S&P, look favorably on such clauses, which could positively impact EAI's credit ratings. (T. 251) Further, according to the Company, as a utility increases its reliance on Purchased Power Agreements ("PPA"), credit agencies, such as S&P, impute a portion of the stream of future fixed PPA payments as debt, which brings about a reduction in the common equity ratio. Mr. Fetter states that this increases perceived risk and the cost of equity will also increase. Rider CM allows for a change in the allowed return on equity between normal rate cases to compensate for the alleged increased risk. (T. 252-255)

EAI witnesses McDonald and Cooper state that the costs covered by Rider CM are material, volatile, and outside the control of the Company and should be considered for automatic adjustment clause purposes. (T. 100-103, 2335-2338, 137-140, T. Ex. 936-937) Mr. McDonald also argues that other State Commissions have approved similar mechanisms to recover purchased capacity costs between rate cases. (T. 141)

Finally, Mr. McDonald notes that, because of the FERC-imposed bandwidth remedy, any increase in CM rider costs between EAI rate cases will decrease EAI's bandwidth payments. Mr. McDonald states that for every $1 increase in the Company's production costs, FERC-imposed bandwidth payments decrease by 80 cents. (T. 145-146, 179)

With the exception of AEEC, all of the other parties oppose implementation of the CM rider. AEEC proposes a significant modification to the Company's CM rider which we will address later.

The Commission is not convinced that the proposed CM rider is appropriate at this time. We agree with the parties' arguments in opposition to the rider. First, the CM rider shifts the risk of fluctuations in capacity costs from EAI and onto customers without providing commensurate benefits to customers. This shift in risk does not adequately balance Company and ratepayer interests. (T. 2403/09) Further, EAI proposes this risk-reduction measure for its shareholders, yet does not propose a corresponding decrease in the allowed return on equity.

Second, the level of costs is not material and currently represents only 1% of EAI's rate schedule revenue requirement. (T. 2403/10) Also, the costs are not volatile. For the period 2000 through 2005, capacity purchase costs have ranged from $1.4 million to

$7.2 million, which does not constitute extreme volatility. In addition, for the most recent three years, 2004 through 2006, capacity purchase costs have not exhibited extreme volatility. (T. 2403/10, 2403/36, 613) Further, the Commission does not agree with EAI that the Company has no control over the costs covered by the CM rider. In contrast with the ECR rider, whose costs are determined by prior portfolio decisions as well as market forces, the Company has significant control over decisions regarding the plant's type, size, location, and dates of construction.

While many utilities have fuel adjustment riders, only a few have capacity adjustment riders similar to rider CM. Furthermore, there does not appear to be an industry-wide movement toward granting capacity adjustment riders in traditional non-retail access jurisdictions. (T. 2403/36-2403/38)

A comprehensive rate review provides a better forum for review and scrutiny of these costs than does the procedure in the CM rider. Moreover, the time constraints embedded in rider CM limit the time for an adequate Staff review and limit participation by other parties in the process. (T. 611-612)

The imputed debt cost component of the CM rider is actually an adjustment to the Company's allowed return on equity. It is neither just nor reasonable for this Commission to give EAI an increase in the allowed ROE though a rider without a full review of existing economic and financial conditions and EAI's overall required rate of return. This is an example of single-issue ratemaking. (T. 614, 982)

In addition, the proposed CM rider creates a mismatch between costs and revenues. The cost of new capacity would be automatically recovered through this mechanism, while existing base rates would allow shareholders to keep all excess revenues arising from load growth and decreases in existing rate base because of accumulated depreciation. (T. 651, 745, 1853-1854)

To address this last problem and because of the FERC-imposed bandwidth remedy, AEEC witness Falkenberg proposes a broader recovery mechanism in conjunction with the ECR. Mr. Falkenberg proposes that all of EAI's production costs, including those in the ECR rider, the proposed CM rider, and the EAI bandwidth payments proposed for the PCA rider be subject to an exact recovery cost rider with seasonal differentiation. Mr. Falkenberg testifies that this approach is beneficial since it would eliminate the likelihood of over-recovery of the costs of a new plant in the subsequent years after its costs are placed in base rates. Mr. Falkenberg also notes that any incentives for "gaming" accounting entries or inefficient management, which normally occur with pass-through recovery mechanisms, are mitigated by his proposal since most of EAI's production costs are reflected in the bandwidth remedy. (T. 1853-1856)

Staff witness Smith opposes Mr. Falkenberg's proposal. (T. 2403/35) AG witness Marcus also opposes the proposal but considers it a significant improvement over EAI's original proposal. However, Mr. Marcus notes that if this revised proposal is adopted there should be a commensurate downward adjustment in the allowed return on equity because of the decrease in risk. (T. 744-745)

EAI's witnesses indicate that Mr. Falkenberg's proposed modification to the CM rider would be acceptable with the exception of the seasonal rate differential. (T. 143, 2300-2302, 178-180, 2313, T. Ex. 925-931)

The Commission will not approve AEEC's alternative approach to a CM rider (T. Ex. 925-931) for many of the same reasons that we discussed above with regard to EAI's proposed Rider CM. First, this proposal does not appropriately balance the interests of ratepayers and shareholders. If this proposal were approved, a significant proportion of EAI's costs would be automatically flowed through to customers. The only remaining costs not automatically flowed through would be transmission and distribution costs. That significantly increases the risk to ratepayers, without any commensurate benefits.

Second, rather than the expedited and truncated process envisioned in a revised CM rider, the Commission believes that a comprehensive rate review process provides a better forum for review and scrutiny of these costs. The time constraints embedded in rider CM severely limit Staff, intervenor, and Commission review.

<u>Production Cost Adjustment Rider ("PCA") –
FERC-Imposed Production Costs</u>

In 2001, the Louisiana Public Service Commission ("LPSC") filed a complaint at the FERC alleging that production costs among the Entergy Operating Companies are no longer "roughly equal" and thus are not just, reasonable and not unduly discriminatory as required by the Federal Power Act. The LPSC asked the FERC to fully equalize all the Operating Companies' production costs. The Commission intervened on behalf of Arkansas ratepayers and vigorously contested the LPSC's complaint. The FERC, in its Opinion Nos. 480 and 480-A, denied the LPSC's demand for full production cost equalization but determined that rough equalization should be maintained through a bandwidth of +/-11% of the system average production cost. Because EAI's production costs are more than 11% below the system average, it will be required to make significant payments to the other Operating Companies. The Commission has appealed the FERC's orders to the United States Court of Appeals for the District of Columbia Circuit, and that appeal is awaiting oral argument and the Court's decision.

In the meanwhile, EAI must begin making payments under the bandwidth beginning in July, 2007. In light of United States Supreme Court precedent, particularly *Mississippi Power & Light v. Mississippi*, 487 U.S. 354 (1988), there is little likelihood that a Commission order refusing to pass the costs of those payments to ratepayers would be sustained. The Commission therefore believes that allowing those costs to be passed through to customers at this time is the most prudent course of action. If the Commission's appeal is granted, those costs will be refunded to EAI ratepayers. If it is not, the Commission will pursue its appeal to the United States Supreme Court.

Method of Recovery

EAI proposes three methods for recovering the production costs imposed by the FERC: rider ECR; a new exact recovery rider, *i.e.*, the Production Cost Allocation ("PCA") rider; or base rates. (T. 101) Other parties argue that is inappropriate to recover these costs in base rates or through the ECR rider.

EAI, Staff, and AEEC agree that, because of the volatility of these costs, base rate recovery is inappropriate. (T. 103-105, 2844-2847, 1834-1837, 2972-2973) EAI argues for inclusion of these costs within the ECR rider because FERC has ordered that they be included in Entergy Service Schedule MSS-3. (T. 101) Other parties argue that these costs should be recovered through a separate rider, and should not be recovered through the ECR rider because the costs are not all energy-related. They also argue that the ECR rider is already too complex and customers should be able to directly see the amount of the FERC-imposed charge without the camouflage of the ECR rider. (T. 2403/16, 2972-

2973, 1838-1839) EAI witnesses Gilliam and McDonald agreed that the Company would not oppose a separate and properly designed rider. (T. 2287, 128)

The Commission agrees with Staff and AEEC that these charges should be recovered from ratepayers through a separate PCA rider[52] because these FERC-imposed charges are of a different nature than the costs included in the ECR rider.

Wholesale-Retail Allocations

EAI witness Schnitzer argues that in the initial year the approximately $284 million of the FERC-imposed charges should be allocated to EAI retail customers using a ninety-three percent (93%) energy allocation factor. (T. 2851-2862, 2866-2879, 2307-2308, T. Ex. 933-934) Mr. Schnitzer makes three arguments to support a 93% energy allocation factor.

First, according to Mr. Schnitzer, the reason for the FERC-imposed bandwidth remedy is the disparities in production costs among the Entergy Operating Companies ("EOCs"), and these recent disparities are driven primarily by increases in natural gas prices. Since the EOCs in Louisiana are more dependent upon natural gas plants, this increase in the price of natural gas has affected them disproportionately. Consequently, EAI's bandwidth payments are caused by an increase in the price of natural gas. (T. 2860-2861, 2868-2869)

Second, Mr. Schnitzer states that the amount that EAI will have to pay to other EOCs is solely attributable to EAI being below the system average in energy-related costs; EAI is above the system average in demand-related costs. Thus, to accomplish the

[52]The PCA amount shall appear on ratepayer bills as a separate line-item labeled "FERC Imposed Entergy System Agreement Production Cost Equalization Payment".

bandwidth remedy mandated by FERC, the only reason for the disparity is EAI's below-average energy costs. (T. 2870-2872)

Third, Mr. Schnitzer states that FERC has determined that these bandwidth payments should be included in Account 555 and flowed through Service Schedule MSS-3, which has been solely related to fuel and purchased power costs. (T. 2874-2876, T. Ex. 1347)

Staff witness Wright argues that the retail allocation should be set at 86.13%, which is the Production Demand Allocation Factor ("PDAF") established by the Commission in Docket No. 96-360-U. Ms. Wright argues that pursuant to a Settlement Agreement in that Docket, which was agreed to by EAI, the retail production demand allocator used in any future proceeding will never exceed 86.13%. According to Ms. Wright, this specific provision was included to protect retail ratepayers from additional production costs resulting from the loss of EAI wholesale load. (T. 2958-2960, 2969-2972, 2981-2983) Ms. Wright also states that the FERC-mandated bandwidth payments are not properly classified as energy since the differences between EAI's fuel mix and the other EOCs' fuel mixes are ultimately the direct result of the type and vintage of generation capacity owned by the companies. (T. 2989)

Additionally, Ms. Wright asserts that EAI, in Docket No. 03-028-U, proposed to protect retail ratepayers from any negative effects which might result from approval of the PPAs due to the operation of the ECR rider, the Grand Gulf rider, and the Arkansas Nuclear One decommissioning cost rider. According to Ms. Wright, the intent of these provisions is to protect retail ratepayers from additional costs associated with jurisdictional allocation issues resulting from the approval of the PPAs and/or the loss of wholesale load. (T. 2960-2961, 2969-2972, 2983-2987)

AG witness Marcus recommends that the bandwidth payments be considered 50% energy-related and 50% demand-related for two reasons. First, the reason for the cost inequities among the EOCs is fuel mix and EAI's historical generation capacity. Second, the cost inequality arises from a combination of demand and energy costs on the various Companies. Mr. Marcus's recommendation is that 86.18% of these costs be allocated to retail. (T. 649-650)

AEEC witness Falkenberg recommends that the bandwidth payments be classified between fixed and variable in the same proportion as EAI's underlying average production costs. Using those factors Mr. Falkenberg recommends an 88.43% retail allocation factor. (T. 1846-1847)

Company witness Schnitzer responds to those proposals with a number of arguments. First, Mr. Schnitzer argues that any retail allocator less than 93% is inconsistent with the FERC decision because that would implicitly allocate part of EAI's bandwidth payments to the affiliated PPAs' loads. Further, such an approach would fail to move EAI's production costs to 89% of the system average. (T. 2852-2858)

Second, the cause of EAI's bandwidth payments is the recent increase in natural gas prices, which disproportionately affect the Louisiana companies. (T. 2859-2860)

Third, the FERC used Service Schedule MSS-3, an energy-related rate schedule, for purposes of flowing through bandwidth payments and receipts among the EOCs. (T. 2861)

Fourth, Mr. Schnitzer argues that the amount that EAI has to pay is solely attributable to EAI's being below the system average in energy-related costs; EAI is above the system average in demand-related costs. (T. 2870-2872)

Fifth, Mr. Schnitzer states that since these bandwidth costs were not addressed in the 96-360-U Settlement, the PDAF factor is not applicable in this instance. (T. 156-158, 169-173)

Finally, Mr. Schnitzer argues that the retail protection mechanisms in Docket No. 03-028-U are not applicable here. (T. 161-162, 174-177)

The two primary reasons for EAI now being required to make payments under the bandwidth approach are the significant decreases in the net plant book values of EAI's expensive nuclear and coal plants since the 1980's because of accumulated depreciation and the recent run-ups in natural gas prices. Since the bandwidth calculations focus on the most recent prior year, the amount of fixed costs, then, is relatively small, while the variable costs are relatively high, caused by high natural gas prices. This means that the primary remaining cause of the bandwidth payments is the recent increases in natural gas prices. That means that the bandwidth payments are predominately energy-related and consequently the PDAF factor does not apply.

Staff's arguments regarding the retail protections provided in Docket No. 03-028-U are misplaced. The retail protections from that docket concern negative impacts flowing from the sale of the EAI baseload units through the PPAs. The sale of those units did not cause the loss in wholesale load. The direction of causation is exactly opposite: It is the loss of wholesale load, specifically the North Little Rock load, which opened up the possibility of the PPAs. Consequently, the reason that the retail allocation factor has increased is not because of the 03-028-U PPAs *per se*, but because of the loss in wholesale load as EAI's wholesale contracts expire.

The only record evidence of the appropriate retail energy factor is shown in EAI Exhibit PBG-13. (T. 933-934) The retail allocation derived from that exhibit is 92.13%, and that is the retail allocation factor to be used here. Until EAI leaves the System Agreement in 2013, in future PCA filings a similarly appropriate retail energy allocation factor should be used, unless it can be shown that the bandwidth payments are not energy-related. Because of our decision on this issue, the EAI retail allocations of the bandwidth payments will also be based on a 93% retail energy allocator.

Other PCA Rider Issues

EAI witness Gillam proposes that a carrying charge be applied to any under- or over-recoveries during the PCA rider year. (T. 2259-2261) The FERC has ordered that EAI's bandwidth payments, based on the year 2006 production costs, will be made over a seven-month period, June through December of 2007. This will be true in the following years as well. EAI proposes that its bandwidth payments be recovered from retail ratepayers over a twelve-month period. According to Mr. Gillam, this will significantly and consistently result in EAI making payments prior to the rate recovery of such payments from Arkansas retail ratepayers. (T. 2288-2290, 2308-2309, T. Ex. 909-910) Mr. Gillam argues that this consistent result is analogous to working capital because of the revenue lag. (T. 2308-2309)

Staff witness Wright responds by stating that a lag in a rate rider such as the PCA does not necessitate a carrying charge. Any lag in the collection of the bandwidth payments could be mitigated by excess earnings as a result of sales growth and depreciation of existing plant over time. Ms. Wright recommends that the proper treatment of any over-or under-recovery balance should be determined closer to the time when EAI exits the Entergy system agreement and based on the circumstances at that time. (T. 2992-2994)

Because of the extremely unusual manner in which FERC has ordered the bandwidth payments be made (over seven months instead of twelve months), EAI's proposed retail recovery over twelve months will consistently result in an under-recovery. For this reason, the Commission finds that it is appropriate to allow EAI a carrying charge equal to the customer deposit interest rate in the context of an annual true-up adjustment for differences between projected sales and actual sales during the recovery year.

Thus, the calculations will be performed in the following steps:

(1) Allocate the FERC-imposed payment to retail rate classes based on the annual energy class allocators;

(2) Determine the class-specific kwh rate by dividing the class-specific FERC-imposed payment by that class's projected annual energy usage during the billing year;

(3) For each rate class and each billing month in the twelve-month period ending with the last day of February in the billing year, accumulate over- and or under recoveries using: (a) the difference between actual class recovery and actual retail payment of the FERC-imposed payment (using the energy allocator for that class); and (b) apply a monthly carrying charge for each class and for each month to the end of the twelve-month period referred to above; and

(4) Sum the over- and over-recoveries with accumulated carrying charges for each class during the twelve-month period ending in February and apply that as a true-up adjustment to be applied to the corresponding class in the following year's annual redetermination.

Additionally, the threshold for an interim adjustment will be 55% of the FERC bandwidth payment included in the most recently filed rate determination under the PCA rider. Seasonal rates are not appropriate for the PCA since the FERC-imposed costs are not seasonal, but fixed monthly over a seven-month period in each calendar year.

The Commission also clarifies that this PCA rider does not include refunds that the FERC may possibly order to be paid by EAI to the other EOCs in FERC Docket No. EL01-88-000. If refunds are ordered by the FERC, EAI must file a separate request to ask for retail recovery of such refund.

Optional Irrigation Control Service Rider - M25

Staff witness Bradley testifies that EAI is proposing the elimination of its Optional Irrigation Control Service Rider, or Rider M25, ("Irrigation Rider"), a rider designed to give irrigation customers a credit for allowing EAI to control the operation of irrigation pumps during periods of curtailment. Ms. Bradley testifies that there were approximately 2,200 customers participating in the program in 2005 and 2006. (T. 3284) Ms. Bradley notes that EAI proposes to eliminate the Irrigation Rider because the control equipment is no longer functional and is not repairable and that, based on the results of the Ratepayer Impact Measure ("RIM") test, continuation of the program is no longer economic. (T. 3285) Ms. Bradley, however, recommends that the program continue because of: the negative impact abrupt cessation would have on over 2,000 customers; her ongoing concern that the RIM test results are not accurate; and the possible hindrance that cessation of the program would have on the Commission's conservation and energy efficiency initiatives of Docket No. 06-004-R.[53] (T. 3285, 3305) Ms. Bradley also asserts that, with certain corrections to the RIM test as well as some changes to the provisions of the tariff, the program could be found economically viable. (T. 3285-3286, 3305)

EAI witness Cooper testifies that he has calculated the RIM test using both his original five year payback period and, in response to Ms. Bradley's concerns, a ten year pay back period, both of which continue to reflect that continuation of the program is not economic. (T. 2343-2344) EAI witness Castleberry testifies that the equipment to control the irrigation pumps has been removed and that EAI no longer has control over the pumps at peak. Thus, Mr. Castleberry continues, should the Irrigation Rider credit remain in place, the reduced rates to these customers will be subsidized by all other customers. (T. 1603) The cost of that subsidy, according to Mr. Castleberry, is approximately $771,068.

The Commission approves the discontinuation of the program in view of the subsidy provided this service by other ratepayers. The Commission finds that the program can no longer be offered economically, given both the RIM test results and the disappointing fact that the older equipment has been removed and cannot be used to reinstate pump control. During the hearing it became apparent to the Commission that while the equipment is no longer usable, because the Company did not maintain the equipment in working order. This is unfortunate given that similar programs are used

[53] In the Matter of a Notice of Inquiry Regarding a Rulemaking for Developing and Implementing Energy Efficiency Programs.

by the electric cooperatives in Arkansas to the benefit of both the customer and the cooperatives.[54] Given the importance that the Commission is placing on demand response and energy efficiency measures in Docket No. 06-004-R, the Commission directs EAI to investigate reinstatement of this program as its BPL pilot project progresses and that EAI address this service in the context of any conservation or efficiency initiatives it may propose.

Master Metering Exemption - GSR 5.20

Ms. Bradley recommends EAI's exemption to General Service Rule ("GSR") 5.20, Master Metering, be rescinded. Ms. Bradley asserts that EAI failed to properly satisfy the Rule's provisions related to a prior application by EAI to replace multiple meters with a single meter. Ms. Bradley testifies that EAI has not appropriately provided the explanations required under Section C of the Rule. (T. 3286, 3307-3309) In response, EAI witness Meyer indicates that EAI is opposed to the rescission. (T. 2586) Ms. Bradley, although recommending rescission, also recommends that customers currently served under the exemption be grand-fathered under EAI's prior service, until such time EAI files for and receives exemption. (T. 3309)

The Commission finds, based on Ms. Bradley's description of EAI's application process, that EAI has failed to comply with the requirements under General Service Rule 5.20 and hereby rescinds EAI's exemption to this rule but reserves the exemption applicable to customers it currently serves under that exemption.

[54]Presentation by Arkansas Electric Cooperative Corporation ("AECC"), May 25, 2007, and comments filed in Docket No. 06-004-R by AECC.

Extension of Facilities and Underground Extension
("EOFP" & "UGP") and Meter Charge

AG witness Marcus recommends changes to EAI's amended line extension policies, Rate Schedule No. 60, Extension of Facilities Policy ("Line Extension Policy") and Rate Schedule No. 61, Tariff Governing The Installation Of Electric Underground Residential Distribution Systems and Underground Service Connections ("Underground Policy"). Mr. Marcus proposes that the calculation which sets the basis for the number of feet provided to customers at no cost - 800 feet in EAI's proposal – be corrected. Mr. Marcus testifies that EAI erroneously established that footage based on a payback period from estimated sales at the new location using the entire bundled rate, rather than just the distribution portion of the rate. Mr. Marcus asserts that this error will result in other ratepayers subsidizing line extensions, particularly to developers. (T. 731-737) When calculated based on the distribution function alone, Mr. Marcus continues, customers would receive only 218 feet at no cost. (T. 735) However, to prevent significant costs to new rural customers taking overhead service, Mr. Marcus testifies that he will accept the 800 feet allowed in the Line Extension Policy. However, with regard to the Underground Policy, Mr. Marcus recommends that base overhead footage be limited to 300 feet. Mr. Marcus assets this is necessary to avoid significant subsidy to developers, who are more likely to opt for underground lines. In conjunction with that limitation, Mr. Marcus recommends that EAI directly charge these customers for meters, rather than include the costs in base rates, noting that this small change will more appropriately balance the interest of developers with the interest of ratepayers. (T. 736-737)

EAI witness Grillo and Staff witness Cotten do not support Mr. Marcus' proposed amendments to the revised tariffs nor do they support separately charging for meters. Mr. Grillo testifies that EAI's originally proposed tariff provisions are cost justified, with the Underground Policy appropriately charging for any differential costs. Both Mr. Cotten and Mr. Grillo testify that the proposed payback calculation used to set the allowed footage in the amended tariffs is no different than that in EAI's current tariffs. Mr. Grillo and Mr. Cotton therefore recommend that the Commission reject Mr. Marcus' changes and his proposal to separately charge for meters and approve the tariffs as recommended by Mr. Cotten. (T. 1088-1091, 1713-1715, 1728-1730)

The Commission finds, for purposes of calculating the pertinent payback period, that limiting the revenue stream to the distribution-only, unbundled portion of the tariff is not appropriate. New customers will contribute incrementally based on collection of the entire bundled rate, and Mr. Marcus does not establish in the record sufficient justification or need for a change from the currently approved methodology. The Commission therefore rejects those proposed changes and adopts both the Line Extension Policy and the Underground Policy as recommended by Staff witness Cotten.

Annual Earnings Review

Under applicable Arkansas law the Company is entitled in this case to a timely final order establishing a prospective retail revenue requirement and appropriate retail rates and tariffs to be effective as of June 15, 2007. Such prospective revenue requirement, rates and tariffs must satisfy the requirements of Arkansas law and fall within the regulatory ratemaking parameters established by the United States Supreme

Court in the Hope and Bluefield cases.[55] The Commission's findings in this order regarding the Company's prospective revenue requirement, rates and tariffs are based upon substantial evidence of record and are just and reasonable. Therefore, such findings are in compliance with both Arkansas and federal law.

However, there are no state or federal legal requirements that require this Commission to approve the Company's proposed Production Costs Adjustment rider[56] ("PCA") or its proposed Capacity Management rider ("CM"). Nor are there any state or federal legal requirements that require this Commission to approve the continuance of the Company's Energy Cost Recovery rider ("ECR"). Clearly the Company is legally entitled to a just and reasonable retail revenue requirement and rates and tariffs that allow the Company the opportunity to recover its prudently incurred public utility operating expenses and to earn a fair return on its capital investment dedicated to the public use. Such revenue requirement must fairly comprehend, among other elements, the Company's prudently incurred costs for energy and fuel expenses as well as for historic and/or new electric generation capacity and associated plant prudently acquired, installed and operated for the public use in furtherance of the Company's public utility obligations.[57] However, the Company is not legally entitled to recover such

---

[55]*Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944); *Bluefield Water Works & Improvement Co. v. Public Sservice Commission of West Virginia*, 262 U.S. 679 (1923)

[56]The Commission does not concede that the Company is entitled to immediate recover from its ratepayers of the System Agreement payments which the Federal Energy Regulatory Commission ("FERC") has ordered it to make to its affiliated operating companies. Further, this Commission continues to pursue its appeal of the FERC's System Agreement orders in the federal courts.

[57]The Commission notes that Entergy Services, Inc., has made a filing with the FERC in Docket No. ER07-93-000 seeking to include in its Open Access Transmission Tariff ("OATT") those costs related to Entergy's unsuccessful efforts to join or form a Regional Transmission Organization ("RTO"). This FERC proceeding has been the subject of ongoing settlement processes at the FERC. This Commission specifically reserves judgment on all issues concerning such costs in any future proceedings before this

costs through automatic riders, such as the PCA, the CM, and the ECR. Under Arkansas law the Commission could require that costs associated with the Company's PCA, the CM, and the ECR be recovered through the normal rate case processes available to the Company.

Though not legally obligated to do so, the Commission has determined herein that conditional approval of the PCA and conditional continuance of the ECR are in the public interest. However, the Commission has determined that approval of the CM is premature and not in the public interest and, therefore, has rejected the CM for the reasons cited elsewhere.

The PCA and the ECR, as modified hereinabove, are approved for a limited-time trial period to end on December 31, 2008, unless expressly authorized by the Commission to be continued beyond December 31, 2008, and subject to the development and implementation of an annual earnings review process ("AER") for the Company. The Commission directs the parties to expeditiously develop and file a proposed AER process for the Commission's consideration. The AER should be designed to be fair and reasonable for both ratepayers and the Company and should comprehend prudently incurred substantial changes to the Company's financial circumstances occurring during the course of the review year, including but not limited to the acquisition by the Company of additional electric generation resources and associated plant as pre-authorized by the Commission. Another objective of the AER shall be to capture any excess earnings above the revenue requirement authorized herein and to credit such excess earnings to the benefit of ratepayers through the PCR. The

Commission examining whether EAI's retail rates are just and reasonable, including the AER process to be developed pursuant to this Order.

Commission envisions an AER process similar to the Regulatory Earnings Review Tariff ("RERT") approved for the Company in Commission Docket No. 98-114-U.[58] However, in the development of the proposed AER, the parties are not obligated to strictly duplicate the RERT process.

The Commission is of the opinion that the proposed AER process can be developed by the parties and submitted for the Commission's consideration and approval within a relatively short period of time, especially if the RERT process is used as the model for the AER. Accordingly, the parties are directed to file the proposed AER process within sixty days of the date of this Order. Allowing for an appropriate procedural schedule for consideration of the proposed AER process, the Commission would hope to approve an acceptable AER to be effective as of July 1, 2007, within 60 to 90 days of the date of filing the AER process.[59]

Assuming an acceptable AER process can be implemented effective July 1, 2007; the Commission will allow the PCA and the ECR to remain in effect until December 31, 2008. Prior to the sunset of the PCA and the ECR on December 31, 2008, the Commission will consider whether such riders should be allowed to continue for calendar year 2009. The Commission's decision to allow the riders to continue for calendar year 2009 will be substantially influenced by the Company's progress towards the development and approval of an amended Entergy System Agreement acceptable to this Commission and the continued effectiveness of the Company's December 19, 2005, Notice to Withdraw from the Entergy System Agreement.

[58]The RERT was approved by the Commission in Order No. 3.

Uncontested Issues

The Commissions finds that the Amended Issues List also delineates those issues upon which the parties have reached agreement. The Commission has considered the record on the issues for which agreement has been reached and finds substantial evidence within the record for the final positions taken. Therefore, for those issues upon which the parties agree, the Commission approves those positions and rate treatment as outlined within the Amended Issues List filed April 23, 2007.

Conclusion

1. Revised retail rates and tariffs in compliance with this Order shall be effective for all electric usage on and after June 15, 2007.

2. EAI shall file with the Commission such revised retail rates and tariffs for review and approval as expeditiously as possible.

3. EAI shall otherwise fully comply with the directives set forth in this Order.

[59]The Commission recognizes that the first earnings review under the AER will cover only 6 months, i.e., July 1, 2007 through December 31, 2007. The second earnings review will cover calendar year 2008.

BY ORDER OF THE COMMISSION.

This 15th day of June, 2007.

Paul Suskie, Chairman

Sandra L. Hochstetter, Commissioner

Daryl Bassett, Commissioner

Diana K. Wilson
Secretary of the Commission

I hereby certify that the following order issued by the Arkansas Public Service Commission has been served on all parties of record this date by U.S. mail with postage prepaid, using the address of each party as indicated in the official docket file

Diana K. Wilson
Secretary of the Commission
Date 6/15/07