124 FERC ¶ 63,026
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Entergy Services, Inc. Docket No. ER07-956-001

INITIAL DECISION
(Issued September 23, 2008)

APPEARANCES

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MICHAEL J. CIANCI, JR., Presiding Administrative Law Judge

I. INTRODUCTION AND GENERAL BACKGROUND

A. Purpose Of Proceeding And Entergy's Prior Compliance Filing

1. This hearing involves rates filed by Entergy Services Inc. (Entergy or ESI)[1] on May 29, 2007, on behalf of the Entergy Operating Companies,[2] pursuant to Service Schedule MSS-3 of the Entergy System Agreement (System Agreement), implementing for the first time, the Commission's decisions in Opinion Nos. 480 and 480-A. On July 27, 2007, the Commission accepted these proposed rates for filing, suspended them for a nominal period, to become effective June 1, 2007, as requested, subject to refund, and ordered this matter to hearing[3].

2. By way of background, on June 14, 2001, the Louisiana Public Service Commission (LPSC) filed a complaint against Entergy, pursuant to section 206 of the Federal Power Act (FPA).[4] The LPSC alleged that the System Agreement (Exhibit No. ESI-4), a rate schedule that includes seven service schedules governing among other things, the allocation of certain costs associated with the integrated operations of the Entergy system, no longer operated to produce rough production cost equalization. As will be discussed more fully below, historically there have been numerous challenges to the Entergy system by the LPSC and other Retail Regulators.

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[1] Entergy Services, Inc. is a wholly owned subsidiary of Entergy Corporation which provides operating services to the five Operating Companies. Energy Power, Inc. (EPI) is a subsidiary of ESI. Systems Energy Resources, Inc. (SERI) is another Entergy affiliate which owns and operates the Grand Gulf nuclear facility. Entergy Corporation is a public utility holding company that provides electric service through the Operating Companies.

[2] The five Entergy Operating Companies are at the relevant times for filing pursuant to the first Bandwidth calculation: Entergy Arkansas, Inc. (or EAI), Entergy Gulf States, Inc. (or EGS), Entergy Louisiana LLC. (or ELL), Entergy Mississippi, Inc. (or EMI), and Entergy New Orleans, Inc. (or ENO). Subsequently, Entergy Texas, Inc. was created and serves load in Texas, but is not subject to these proceedings.

[3] *Entergy Services, Inc.*, 120 FERC ¶ 61,094 (2007).

[4] 16 U.S.C. ¶ 791a et. seq.; ¶ 824 *et. seq.* (2008).

3. In Opinion No. 480,[5] the Commission, adopted the Initial Decision of Presiding Administrative Law Judge Lawrence Brenner[6] and found that rough production cost equalization had been disrupted on the Entergy system. Opinion Nos. 480 and 480-A approved a numerical Bandwidth of +/- 11 percent of the Entergy system average production cost in order to maintain the rough equalization of production costs among the Entergy Operating Companies and required annual filings beginning in June 2007. The Commission stated that the Bandwidth would be implemented prospectively and would be effective for calendar year 2006, and that any equalization payments would be made in 2007 after a full calendar year of data became available.

4. On April 10, 2006, Entergy initially submitted a compliance filing[7] to implement the directives of Opinion Nos. 480 and 480-A, but it included proposed revisions to Service Schedule MSS-3[8] that had not been ordered by the Commission in Opinion Nos. 480 and 480-A. In its Order accepting the compliance filing,[9] the Commission rejected "these non-compliant amendments and denied, as beyond the scope of the compliance filing, Entergy's request to make adjustments to the methodology reflected in Exhibits ETR-26 and ETR-28." The Commission stated that Entergy should make a section 205 filing if it desired to make any changes to the methodology in Exhibits ETR-26 (Exhibit No. ESI-9) and ETR-28 (Exhibit No. ESI-10).

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[5] *Louisiana Public Service Comm'n v. Entergy Services, Inc.*, (Opinion No. 480), 111 FERC ¶ 61,311 (2005), *aff'd, Louisiana Public Service Comm'n v. Entergy Services, Inc*., 113 FERC ¶ 61,282 (2005) (Opinion No. 480-A).

[6] *Louisiana Public Service Comm'n v. Entergy Services, Inc.*, 106 FERC ¶ 63,012 (2004).

[7] *Entergy Services, Inc. Compliance Filing* Docket No. EL01-88-004 (2006).

[8] Service Schedule MSS-3 includes a methodology for pricing energy exchanged among the Operating Companies and provides for an after-the-fact, hour-by-hour allocation of the cost of energy from an Operating Company whose generation provided energy in excess of that company's load to an Operating Company that produced less than its load. Entergy also has included the formulas for implementing the rough production cost equalization Bandwidth remedy required by Opinion No. 480 in Service Schedule MSS-3.

[9] *Louisiana Public Service Comm'n v. Entergy Services, Inc.*, 117 FERC ¶ 61,203 (2006).

5. Another compliance filing was filed on December 18, 2006 and accepted by the Commission on April 27, 2007.[10] Additionally, on March 30, 2007 and April 6, 2007, the Operating Companies submitted certain proposed modifications to the December 18, 2006 Compliance Filing.[11] On May 25, 2007, the Commission issued additional orders regarding those filings.[12] According to Entergy, the proposed rates were calculated in accordance with the Service Schedule MSS-3, as revised, pursuant to the May 25 Orders.

B. Entergy's Current Compliance Filing

6. On May 29, 2007 Entergy filed rates in accordance with Service Schedule MSS-3 of the System Agreement, as revised pursuant to the May 25 Orders, implementing the Commission's decisions in Opinion Nos. 480 and 480-A. That filing is now the subject of this hearing.

7. In the current filing, Entergy calculated the Bandwidth payments and receipts under the Service Schedule MSS-3 Bandwidth formula using data as reported in the Operating Companies' 2006 FERC Form No. 1. Each Operating Company's allocated Average Production Costs are compared to the Operating Company's Actual Production Costs to determine the dollar and percent disparity, as seen below:

	Initial Disparity	**Final Disparity**
Entergy Arkansas, Inc.	-27.99%	-11.00%
Entergy Gulf States, Inc.	8.68%	3.45%
Entergy Louisiana, LLC	8.80%	3.45%
Entergy Mississippi, Inc.	8.00%	3.45%
Entergy New Orleans, Inc.	-2.44%	-2.44%

[10] *Louisiana Public Service Comm'n v. Entergy Services, Inc.*, 119 FERC ¶ 61,095 (2007).

[11] *See* March 30, 2007 filings in Docket Nos. ER07-682-000, ER07-683-000 and ER07-684-000, and April 6, 2007 filing in ER07-727-000.

[12] *Entergy Services, Inc.*, 119 FERC ¶ 61,190 (2007); *Entergy Services, Inc.*,119 FERC ¶ 61,191 (2007); *Entergy Services, Inc.*, 119 FERC ¶ 61,192 (2007); *Entergy Services, Inc.*, 119 FERC ¶ 61,193 (2007) (*collectively*, May 25 Orders).

8. Entergy Arkansas is the only Operating Company to have an initial disparity exceeding +/- 11 percent. Thus, as seen below, it was the only company obligated to make payments:

	(Payment)/Receipt in Millions of Dollars
Entergy Arkansas, Inc.	(251.7)
Entergy Gulf States, Inc.	120.1
Entergy Louisiana, LLC	91.0
Entergy Mississippi, Inc.	40.6
Entergy New Orleans, Inc.	0

9. Entergy requested that the Commission accept the proposed rates for filing without suspension, hearing, or investigation. Additionally, Entergy requested waiver of the 60-day prior notice requirement and an effective date of June 1, 2007.

C. The Responsive Pleadings

10. Notice of the filing was published in the *Federal Register*, 72 FR 33,478, with interventions and protests due on or before June 19, 2007. Motions to intervene were duly filed and accepted by: Occidental Chemical Corporation; City of Osceola, Arkansas; Arkansas Electric Energy Consumers, Inc; Louisiana Energy Users Group; East Texas Electric Cooperative, Inc. (ETEC); Sam Rayburn G&T Electric Cooperative, Inc.; and Tex-La Electric Cooperative of Texas; the LPSC; the Mississippi Public Service Commission (MPSC); the Arkansas Public Service Commission (APSC), and the Council of the City of New Orleans, Louisiana (CNO) (collectively, the Retail Regulators). Certain Retail Regulators also filed protests.

11. On July 5, 2007 Entergy filed another answer to the protests. On July 18, 2007 the LPSC filed an answer. On July 23, 2007, the APSC filed an answer. On July 25, 2007, Entergy filed an answer. The Commission in is Order dated July 26, 2007, setting this matter for hearing, struck the answers of the parties, noting answers are generally not accepted in protests. Late intervenors were accepted, including the Public Utility Commission of Texas (PUTC); Texas Industrial Energy Consumers; the Cities of Nederland, Port Neches and Silsbee, Texas; and, Union Electric Co. dba Ameren UB (Ameren). Only the following parties appeared and actively participated at the hearing, which started on June 17, 2008, and ran on consecutive days through July 3, 2008: Entergy, LPSC, APSC, MPSC, Ameren, CNO, ETEC and the FERC staff.

12. The LPSC argued in its protest that Entergy's filing failed to reflect the requirement of Service Schedule MSS-3, effective May 30, 2007, because it did

not calculate net area load requirements as they were calculated in Exhibits ETR-28 and ETR-26 from Docket EL01-88 as required by the Commission. Additional errors have been raised by the LPSC which involve accounting errors, and which are addressed in this decision.

13. Moreover, the LPSC alleges Entergy has acted with imprudence, which has impacted and artificially raised actual production costs. Initially, these allegations involved Entergy's practices with regards to transmission planning, failure to purchase lower cost energy allegedly available on the wholesale market, and Entergy's generation planning practices. At hearing, the alleged imprudence issue centered upon the LPSC's assertion that ESI through Entergy Arkansas, imprudently declined to repurchase 164-180 MW of generation capacity in an 842 MW coal –fired generation plant, in the Industrial Steam Electric Station Unit No. 2 (ISES 2).

14. Initially, certain Retail Regulators also voiced concerned that the Commission's ruling(s) in this case could establish binding precedent, which may preclude them from examining the prudence of cost inputs in retail rate cases. The Retail Regulators requested that the Commission clarify that the scope of this proceeding is limited solely to whether or not the Bandwidth payments/receipts calculated by Entergy are just, reasonable, and not unduly discriminatory or preferential and does not extend to a consideration of whether the actual cost inputs underlying the calculations are just, reasonable and prudent.

15. Alternatively, some of the Retail Regulators argued that even if the Commission determines that the scope of this proceeding includes a consideration of whether or not each of the underlying cost inputs supporting Entergy's proposed Bandwidth payments/receipts are just, reasonable and prudent, Entergy's underlying cost inputs lack sufficient detail to enable any interested party to ascertain the prudence of such costs. The Retail Regulators urged the Commission to set this proceeding for hearing, which it did in its July 26, 2007 Order.

16. Finally, certain Retail Regulators initially argued that Entergy proposed to use the same methodology for allocating costs between wholesale and retail loads and between retail jurisdictions of a single Operating Company that the Commission rejected in Docket No. ER07-683-000.[13] Therefore, the Retail Regulators urged the Commission to reject this portion of Entergy's filing.

[13] *See Entergy Services, Inc.*, 119 FERC ¶ 61,191 (2007).

D. The Commission's Order Establishing Hearing and Settlement Procedures

17. Ultimately, the Commission's Order expressly instructed the undersigned to hear evidence pertaining to the underlying production costs from which Entergy calculated its filing, and allows the parties to present evidence of imprudence.

> All parties will have the opportunity to raise prudence issues, as we explained in our recent order denying the Arkansas Public Service Commission's complaint in Docket No. EL06-76-000.[14]

18. The Commission then addressed the Retail Regulators jurisdictional concerns.

> While this proceeding will ultimately result in a Commission determination that will be binding on the states with respect to the Bandwidth payments and receipts, and that determination necessarily will be based on underlying cost inputs and the reasonableness thereof, the Commission cannot determine, absent specific facts, all the circumstances in which a state might be preempted from reviewing the prudence of the underlying production costs incurred for the system at that time.[15]

19. Therefore, the Commission clearly ordered a complete and comprehensive review of all relevant issues pertaining to the proper allocation of Bandwidth payments and receipts to wholesale customers, as well as any and all imprudence issues relating to the underlying production costs used by Entergy to calculate and support its aforementioned May 29, 2007 filing. The Commission, however, expressly stated that issues related to the allocation of such payments and receipts among retail customers "is beyond the jurisdiction of this Commission". Therefore, the undersigned is mindful of the jurisdictional distinction noted by the Commission and this decision does not purport to address such issues.

20. Not withstanding this jurisdictional concern, the Commission found genuine issues of material facts exist which need to be examined at an evidentiary hearing.

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[14] *Entergy Services, Inc.*, 120 FERC ¶ 61,094 at 5 (2007).

[15] *Id.* (Use of short citing to legal citations is limited for the convenient of the reader).

> Our preliminary analysis indicates that Entergy's proposed rate schedule has not been shown to be just and reasonable and may be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful. Therefore, we will accept Entergy's proposed rates for filing, suspend it for a nominal period, make it effective June 1, 2007, as requested, subject to refund, and set it for hearing and settlement judge procedures.[16]

II. THE HISTORY OF ROUGH PRODUCTION COST EQUALIZATION

21. A brief discussion of the history of rough production cost equalization is necessary to provide the framework for analyzing the legal sufficiency of Entergy's May 29, 2007 compliance filing with Opinions 480 and 480-A. The following is a brief summary of the relevant precedent regarding production cost equalization among the Entergy Operating Companies, based upon Judge Brenner's summary from his Initial Decision.[17]

22. The 1982 Entergy System Agreement has been the subject of extensive administrative litigation leading to the decisions that were considered initially on appeal in 1985 in Commission Opinion No. 234.[18] The Commission had initially attempted to assure equality within the Entergy system by using measures less stringent than rough cost equalization.

23. The D.C. Circuit reviewed the decision of the Commission, as embodied in Opinion Nos. 234 and 234-A.[19] In examining the historical operation of the System Agreements on the then Middle South Energy (MSU) System (predecessor to Entergy), the Court stated the following:

> Since 1951 the MSU system has sought to iron out the inequities that would otherwise result where some companies were long while other companies were short through a system of "equalization payments." Prior to 1973 each "short" company made a payment to the "long" companies based on a fixed dollar amount per

[16] *Id*. at 6.

[17] *Louisianna Public Service Comm'n v. Entergy Services, Inc.*, 106 FERC ¶ 63,012 at P 13-24 (2004); also at n.6.

[18] *Middle South Energy, Inc.*, 31 FERC ¶ 61,305 (1985).

[19] *Mississippi Industries v. FERC*, 808 F.2d.1525 (D.C. Cir. 1987).

> kilowatt of capacity that the company was short. In 1973 the System Agreement was amended to provide for capacity equalization payments calculated under the "participation unit" formula, a formula that based payments on the ownership costs of the latest unit constructed by the "long" company.[20]

24. Because of the unexpected rise in the cost of constructing nuclear power units, the Court recognized that the 1973 System Agreement was unworkable since "continued application of a capacity equalization scheme that only sought to equalize *kilowatts* could no longer come close to equalizing investment *dollars*."[21]

25. The Court recognized that with the 1982 System Agreement, "the cost burden of system generating capacity has been shifted among the affiliates, by virtue of Commission action and system agreement, in order to insure an equitable distribution." Looking at the relationship between capacity costs and wholesale rates, the Court found that "[u]nreasonable disparities in the shares borne by affiliates of the total costs of the system's generating capacity plainly 'affect' the wholesale rates at which the Operating Companies exchange energy, and therefore require remedial action by the Commission pursuant to section 206."[22]

26. Regarding the issue of production cost equalization, the Court explained that "Petitioners' main contention is that the Commission failed adequately to explain its decision not to order full production cost equalization. We find this contention without merit and hold that the Commission acted within its discretion in ordering a less intrusive means of remedying the undue discrimination found on the System."[23] The Court further held the following:

> But we have also concluded that the Commission's chosen remedy is sufficient to remedy the *undue* discrimination on the System; that is, the Commission could properly conclude that the remaining cost disparities do not constitute unlawful discrimination. The Louisiana parties do not seriously dispute this conclusion. Rather, their

[20] *Id*. at 1530 (citations omitted).

[21] *Id*. at 1532.

[22] *Id*.. at 1541.

[23] *Id*. at 1565.

> argument is that production cost equalization would remedy System cost disparities even more effectively than nuclear investment cost equalization and that the Commission did not adequately justify its decision to reject the former and adopt the latter.[24]

27. The Court examined the Commission's decision regarding production cost equalization as follows:

> In deciding whether to order production cost equalization or nuclear investment equalization, the Commission confronted a major policy choice. Though both alternatives would remedy undue discrimination, the former would represent a dramatic disruption of the System's historical operations and of the states' settled interests and expectations. Accordingly, FERC chose the latter alternative. We hold that the Commission's decision was both rational and within its discretion.[25]

28. In summary, the Court held that the "System agreements have sought simply to equalize the System's *excess* energy and capacity among the companies. The *result* has been *rough* equalization of capacity and production costs."[26] Furthermore, the Court stated that "[h]aving found that 'it is the large cost escalations of Grand Gulf and Waterford (nuclear generation units) that have disrupted this pattern [of rough equalization],' the Commission properly decided to take only those steps that were necessary to compensate for this disruption. Those steps were to approve the 1982 System Agreement as filed and order nuclear capacity cost equalization."[27] The Court further stated that it believed production cost equalization would eliminate virtually all production and capacity cost disparities among the Operating Companies.

29. The DC Circuit concluded its opinion with a section affirming the Commission's rejection of the ALJ allocation of investment costs associated with the Grand Gulf nuclear facility. Judge Bork wrote an opinion concurring in part and dissenting in part with the majority. Initially, the petitions for rehearing of the CNO, Mississippi Industries, the Mississippi Attorney General, the Mississippi

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[24] *Id.* (citations omitted) (emphasis in original).

[25] *Id*.

[26] *Id*. at 1566 (emphasis in original).

[27] *Id*.

Public Service Commission, and Mississippi Power and Light Company were denied on April 3, 1987.[28]

30. However, upon reconsideration, the Court vacated its Order of April 3rd and reversed the Commission's decision. The Court further remanded the case to the Commission on several issues and vacated the aforementioned section of the Court's own January 6, 1987 opinion dealing with the allocation of investment costs associated with Grand Gulf.[29]

31. In Opinion No. 292, the Commission responded to the Court of Appeals' remand to explain the criteria for "undue discrimination."[30] In reviewing its decision in Opinion No. 234, and the D.C. Circuit's opinion, the Commission noted that "we found that production costs were *roughly* equalized, and that decisions to install generating capacity were made *primarily* for the benefit of the system as a whole."[31]

32. The Commission further elaborated on what constituted undue discrimination in the context of production costs on the System as follows:

> Nonetheless, over time, the rotational scheme, in conjunction with the terms of the 1951 and 1973 System agreements, resulted in a rough equalization of production costs among all of the individual members of the MSU pool. The pattern of rough equalization of production costs broke down, however, due to the problems the MSU System encountered in constructing nuclear generation. The allocation of Grand Gulf capacity which we ordered in Opinion No. 234, when coupled with the provisions of the 1982 System Agreement, will restore the pattern of rough equalization of production costs which had previously existed among the MSU pool members, and it does so with as little disturbance to the manner in which the MSU System has conducted its integrated operations as is possible under the circumstances….

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[28] *Mississippi Industries v. FERC*. 814 F.2d 773 (D.C. Cir 1987).

[29] *See Mississippi Industries v. FERC*, 822 F.2d 1104 (D.C. Cir 1987).

[30] *System Energy Resources, Inc.*, 41 FERC ¶ 61,238 (1987).

[31] *Id*. at 61,612 (emphasis in original).

> In sum, while the court is correct that we did not, in Opinion No. 234, set forth specific criteria for determining when undue discrimination exists, we believe that our Opinion did implicitly apply criteria that are firmly embedded in the factual setting of the two agreements we were reviewing. Explicitly stated, our criteria for determining when undue discrimination exists in this case were that each operating utility should contribute investments to meet the capacity needs of the system in the long term, and that each operating utility should share in the overall capacity costs of the system in rough proportion to the benefits it receives (i.e., that its demand is met) from that system. Given the tremendous disparities in size and loads among the operating utilities, the only legitimate way to ensure that approximate parity between costs borne and benefits received is to ensure approximate equalization of cost responsibility on a per unit of demand basis. In other words, an allocation scheme that would not achieve a rough equalization of production costs on a demand basis would be, in the absence of a rational explanation, unduly discriminatory because there would be no basis for disparity among similarly situated entities. Hence, our criterion for determining undue discrimination in this context is derived from the factual setting of the principles underlying the complex agreements we were reviewing, not from more general notions of when undue discrimination occurs in regulated industries. However, as noted, this criterion is in conformity with a traditional Commission principle for allocating investment costs.[32]

33. The Commission did note that the "[a]llocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science."[33] However, the Commission justified its decisions as follows:

> We believe that the decision to equalize the investment costs of all the MSU System's nuclear generation (on a demand basis) is reasonable in light of the facts that: (1) the MSU System encountered various difficulties in constructing nuclear units; (2) as a result, there exist disparities in nuclear investment costs per megawatt of demand which are unjustified by factual circumstances; and (3) the costs associated with non-nuclear generation on the integrated, MSU System were roughly

[32] *Id*. at 61,617 (citations omitted).

[33] *Id*. at 61,618.

> comparable. In short, the unique nature of the problems associated with nuclear generating units provided the Commission with a rational reason for focusing upon that group of plants alone.[34]

34. Therefore, at that time, the Commission found it "unnecessary to adopt a more comprehensive form of production cost equalization" for the MSU System, focusing instead on equalization pertaining to nuclear investment.[35]

35. In Opinion No. 292-A, the Commission considered the request of the Arkansas-Missouri Parties and the CNO for rehearing of the Commission's decision in Opinion No. 292.[36] Regarding the issue of cost equalization, the Commission wrote the following:

> In stating that our allocation was consistent with the objectives of the 1982 System Agreement, we alluded to several provisions, among them section 3.01. That provision lists the objective of equalizing imbalances of costs of facilities used for the mutual benefit of the companies. Clearly, equalizing responsibility for the investment costs of the System's nuclear units, given that all of them were planned, built, and are operated primarily for the benefit of the System as a whole, is consistent with this objective. We find no reason to alter our conclusion on this point.[37]

36. On appeal from the final decision of the Commission in Opinion No. 292-A, the D.C. Circuit affirmed the Commission's decision.[38] The Court found the Commission had properly explained the criteria for when undue discrimination exists, and that FERC's allocation of system capacity costs in proportion to system demand was correct. Other subsequent proceedings, however, followed. The LPSC and the CNO filed a new complaint on June 14, 2001 to determine whether the Entergy system was in rough production cost equalization. Eventually, a hearing was held before Judge Brenner from July 7, 2003 through August 22, 2003 to determine the precise issue of rough production cost equalization.

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[34] *Id*. at 61,619-20.

[35] *Id*.

[36] *System Energy Resources, Inc.*, 42 FERC ¶ 61,091 (1988).

[37] *Id*. at 61,425.

[38] *City of New Orleans v. FERC*, 875 F.2d 903 (D.C. Cir. 1989).

37. The evidentiary record in Judge Brenner's hearing consisted of 6,218 pages of hearing transcripts and over 390 exhibits. As indicated, Judge Brenner determined the Entergy system was not achieving rough cost equalization. That hearing eventually gave rise to the Commission adopting Judge Brenner's decision in Opinions 480 and 480-A, which established the legal foundation for this hearing by mandating the +/- 11% Bandwidth formula for rough production cost equalization.

III. THE ISSUES

A. Joint Statement Of Issues (Second Revised).[39]

1. What is the legal effect of any deviation in either Entergy's Bandwidth filing in this docket or any proposed change to ESI's Bandwidth filing in this docket from: (a) the MSS-3 Bandwidth Formula Rate on file with the Commission; or (b) the methodology employed in Exhibits ETR-26 and ETR-28 in FERC Docket EL 01-88?

2. What should ESI have used as the source of data for the variable "ER" for the 2006 Bandwidth calculation (the "Net Area Load" issue)?

3. What is the proper accounting for a tax refund to be received in 2006 for a net operating loss carry-back associated with Hurricanes Katrina and Rita and should those amounts that were included in Account 165 at December 31, 2005 be included for the 2006 Bandwidth calculation?

4. (a). What is the proper accounting for Hurricanes Katrina and Rita related damage costs, recoveries, related regulatory assets and regulatory liabilities? (b). How should Hurricanes Katrina and Rita related damage costs/recoveries be reflected in the 2006 Bandwidth calculation?

5. What accumulated deferred income tax (ADIT) amounts should

[39] These are the agreed upon issues verbatim as submitted by the parties for determination at this hearing. The undersigned finds this joint list of issues fully addresses the matters set for hearing by the Commission. Another set of issues was submitted after the hearing and after the record was closed, by a party which purported to contain very minor stipulated changes to one issue. The undersigned finds the purported changes to be inconsequential.

have been included for the 2006 Bandwidth calculation?

6. What is the appropriate nuclear depreciation and decommissioning expense that should be used for the 2006 Bandwidth calculation?

7. Have costs been misclassified to Account No. 923, Outside Services Employed and, if so, how does that impact the 2006 Bandwidth calculation?

8. What method should be used to properly remove the administrative and general expenses (A&G) and Other Taxes associated with the 30% share of the capacity of the River Bend nuclear facility prior to the functionalization of such costs in the 2006 Bandwidth calculation?

9. (a). How should EGS' costs of acquiring the Spindletop Gas Storage Facilities and the Spindletop Gas Storage Facilities regulatory asset have been accounted for? (b). How should EGS' costs of acquiring the Spindletop Gas Storage Facilities and the Spindletop Gas Storage Facilities regulatory asset-related costs have been reflected in the 2006 Bandwidth calculation?

10. How should the ADIT allocated for purposes of the 2006 Bandwidth calculation reflect the Waterford 3 Sale/Leaseback?

11. Should "interruptible load" be included in the data for the variable "DR" in the 2006 Bandwidth calculation?

Prudence issues:

1. Were the 1996 and 1997 decisions not to exercise EAI's option to purchase ISES 2 capacity imprudent?

2. If it is found that the 1996 and 1997 decisions not to exercise EAI's option to purchase ISES 2 capacity were imprudent what is the remedy and/or what adjustments should be made to the 2006 Bandwidth calculation?

Ameren UE Contract issue:

1. What is EAI's ability to recover Bandwidth payments from Ameren UE under the 1999 Service Agreement between EAI and Ameren UE?

2. If EAI may not recover Bandwidth payments from Ameren UE under the 1999 Service Agreement, what is the obligation to pass through Bandwidth credits to ETEC under the 2004 Service Agreement between EGS and ETEC?

IV. THE POSITIONS OF THE PARTIES

38. The undersigned finds this case can be divided into six distinct areas of importance: The legal effect (correct methodology) issue; the imprudence claims; the Ameren contract issue; the nuclear depreciation and decommissioning issue; the variable net load issue; and the remaining accounting issues.

A. Legal Effect/Methodology Issue

39. Entergy (with the APSC and the MPSC), argue that under the filed rate doctrine, the applicable methodology which governs the Bandwidth formula is now controlled pursuant to Service Schedule MSS-3, the filed and lawful tariff. These parties also assert that Entergy amended Service Schedule MSS-3 in its compliance rate filing, to allow for use of FERC Form 1 data to determine the variable energy allocator for determining the net area load issue, and these amendments should control the issues in this proceeding.[40] They allege, ETR-26 and ETR-28 remain important as guidance, but is no longer controlling in determining the Bandwidth formula.[41]

40. The FERC Staff agrees with Entergy in part. Staff also believes Service Schedule MSS-3 governs Entergy's filing (Exhibits S-1 at 5-8, 25). Furthermore, Staff agrees with Entergy that the Service Schedule MSS-3 governs the variable net load issue. However, Staff asserts that ETR-26 and ETR-28 still controls methodology in determining the Bandwidth formula, if the Service Schedule MSS-3 does not address the issue(s), because the Commission has previously determined these documents will be used.[42]

41. The LPSC recognizes the Service Schedule MSS-3 is the filed tariff but argues that for purposes of determining the Bandwidth calculations, Entergy should not have deviated from using ETR-26 and ETR-28 in any manner,

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[40] *See Louisiana Public Service Comm'n v. Entergy Services, Inc.*, 117 FERC ¶ 61,203 (2006); *Louisiana Public Service Comm'n v. Entergy Services, Inc.*, 119 FERC ¶ 61,095 (2007); also at nn.9&10.

[41] Entergy's Initial Brief (IB) at 8-9.

[42] FERC Staff's Reply Brief (RB) at 2-3.

regardless of any errors following this methodology may cause, and that Entergy did not provide sufficient notice to the public to cover the changes made in the ER variable. The LPSC also argues that Entergy must follow ETR-26 and ETR-28 exactly in determining the Bandwidth calculations, essentially taking the position that no judgment call or deviation of any kind can be made.[43]

42. Ameren, the ETEC, and the CNO essentially take no position on this issue.

B. Imprudence Issue

43. The LPSC contends that Entergy Arkansas imprudently failed to repurchase a portion of the ISES 2 from EPI in 1996 and again in 1997. According to the LPSC, Entergy's decision making process was unreasonable because there was essentially no "process" at all. The LPSC's calculations indicate that in 1996 ISES 2 had a twenty-year net present value benefit.[44]

44. After adjusting for subsequent sales of the ISES 2 capacity that predate the 2006 compliance filing test year, the LPSC calculates the total savings lost by the failure to repurchase ISES 2 to be approximately $23 million. Consequently, the LPSC urges the Commission to find that Entergy's declination to repurchase ISES 2 was imprudent and to adjust the Bandwidth calculations accordingly.

45. Moreover, the LPSC urges the Commission to recalculate the 2006 Bandwidth calculation to account for the savings that were lost due to Entergy's imprudent decision to not repurchase ISES 2.

46. The APSC, the MPSC, the CNO, Ameren and the ETEC do not join the LPSC on the imprudence issue. The APSC supports Entergy's position that Entergy was not imprudent for not reacquiring the ISES 2 capacity, however, the APSC argues that if found to be imprudent, Entergy's shareholders should pay for any losses, not the Arkansas rate payers.[45]

47. Moreover, according to the APSC it had and has, a surplus of base load capacity. Consequently, if Entergy Arkansas had repurchased the ISES 2 capacity in 1996 or 1997, then the APSC contends that the System Agreement would have required it to immediately sell that capacity to the other Operating Companies.

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[43] LPSC IB at 1-5.

[44] LPSC IB at 64, 85-86, 96-98.

[45] APSC IB at 61-71.

The APSC then demonstrates that there is a substantial difference in Entergy Arkansas' Bandwidth payments and receipts depending upon which Operating Companies purchased the ISES 2 capacity.

48. If Entergy Louisiana purchased the capacity, then Entergy Arkansas' Bandwidth payments would decrease by approximately $8 million; Entergy Gulf States and Entergy Mississippi's Bandwidth receipts would increase by approximately $38 million and $10 million, respectively; and Entergy Louisiana's Bandwidth receipts would decrease by approximately $56 million. If Entergy Gulf States received the capacity then Entergy Arkansas' Bandwidth payments would have decreased by $8 million; Entergy Louisiana's and Entergy Mississippi's Bandwidth payments would have increased by $19 million and $9 million, respectively; and Entergy Gulf States' Bandwidth receipts would decrease by approximately $36 million.

49. However, should the Commission decide that Entergy's decision to not repurchase ISES 2 was imprudent and that Entergy Arkansas' Bandwidth payments need to be increased, the APSC asserts that any imprudently incurred costs should logically be borne by the imprudent party, Entergy and its shareholders, as opposed to the otherwise innocent consumers of Arkansas.[46]

50. Entergy disagrees with the LPSC's claim that it imprudently failed to repurchase ISES 2. Entergy claims that its decision to decline its option to repurchase ISES 2 was based on its 1995 Integrated Resource Plan (IRP), which demonstrated that no new capacity was needed to serve load until 2005. In fact, Entergy claims that in 1996 increased cogeneration and the threat of Retail Open Access left it far more worried about a shortage of load as opposed to a shortage of generation.[47]

51. Furthermore, the IRP suggested that Entergy meet any unforeseen increase in load with a combination of surplus generation and capacity purchases from the market. Ultimately, Entergy claims that the IRP and the state of the market clearly directed it to maximize flexibility in resource deployment. As such, Entergy claims that its decision to decline ISES 2 was supported by reasonable analysis and was not imprudent.

52. Entergy also argues should the Commission find imprudence, it should not adopt the LPSC's calculation of damages. First, Entergy notes that the LPSC does not account for the initial capital cost of purchasing ISES 2, which Entergy would

[46] *Id.* at 70.

[47] Entergy IB at 41-46.

presumably has recovered from consumers in higher rates. To ignore these higher rates would essentially bestow a windfall on consumers without an allocation of any of the costs.[48]

53. Second, Entergy urges the Commission to reject the APSC's calculation of damages because it would effectively require the Commission to impermissibly set the Entergy Operating Companies' retail rates.

54. Finally, Entergy asserts that even if Entergy Arkansas should have purchased ISES 2 capacity in 1996, only 79 MW of additional ISES capacity could be attributed to Entergy in 2006 because EPI only offered Entergy Arkansas at most, 180 MW of ISES capacity in 1996, and Entergy subsequently purchased 101 MW of EPI's ISES 2 capacity, which leaves only 79 MW available for purchase in 2006.

55. With respect to the ISES 2 repurchase opportunity, the FERC Staff recognizes that Entergy's decision making process may have suffered from some flaws, but Staff finds little evidence demonstrating that the decision was imprudent. Staff notes that gas was incredibly cheap at the time and coal was not an attractive option. Nor was there much hope for coal on the horizon. Ultimately, Staff urges the Commission to find that Entergy's declination of its right to repurchase ISES 2 in 1996 was not imprudent.

C. Ameren Contract Issue

56. According to Ameren, the 1999 Service Agreement (1999 Agreement) between Ameren and EAI prohibits the pass-through of rough production cost equalization (RPCE) payments. Ameren asserts the 1999 Agreement only permits the pass-through of "Purchased Energy Expenses Charged to Account 555."[49]

57. Though these RPCE payments are recorded in Account 555, Ameren believes that they are not "Purchased Energy Expenses" because they do not reflect a purchase of energy by EAI, whether from a third party of from the Entergy system pool.

58. Ameren further asserts the Commission's Compliance Order supports Ameren's position because it recognizes that RPCE payments are not production costs of service for the prior year; rather, they are a prospective remedy, with no interest accruing, designed solely to bring the Entergy Operating Companies' costs

[48] *Id.* at 86-88.

[49] Ameren IB at 9-12.

into rough equalization.

59. Furthermore, Ameren claims that the inclusion of RPCE payments would upset the very purpose of the contract, which was to secure low cost energy for Ameren. According to Ameren, this purpose is reflected by the contract's high fixed capacity costs and low, albeit variable, energy costs. Finally, Ameren argues that Entergy's public policy argument fails to meet the standard for abrogating a FERC-jurisdictional contract.[50]

60. Entergy asserts the Bandwidth payments are Purchased Energy expenses under the formula rate and as such are allocable to Ameren. Entergy claims that the 1999 Agreement permits Entergy Arkansas to recover all "energy-related costs" that are recorded in Entergy Arkansas' Account 555, which includes Bandwidth Payments. Given that the Bandwidth Payments are directly attributable to the energy service that Entergy Arkansas provides to Ameren, Entergy Arkansas contends that they are energy-related, and because the Commission has determined that the Bandwidth Payments should be booked in Account 555, Entergy contends that they must be allocated to Ameren under the 1999 Agreement.[51]

61. In addition, Entergy notes that it has consistently billed Ameren for energy exchange costs incurred pursuant to the Service Schedule MSS-3 of the Entergy System Agreement and that Ameren has never previously objected to these charges. Given that the Bandwidth Payments are the result of the Commission's determination that Entergy did not properly allocate energy production costs pursuant to Service Schedule MSS-3, Entergy believes that there is no reason that Ameren should not be required pay to its share of these "reallocation" costs as determined by the Commission.[52]

62. Finally, Entergy wholly disagrees with Ameren's reading of the intent of the contract. According to Entergy, the Ameren Service Agreement was amended in 1999 to eliminate a fixed energy component and to make Ameren subject to variations in fuel price, which was an attractive option at the time given the relative low price of fuel.

63. The APSC asserts that the $251.7 million Entergy Arkansas 2006

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[50] *Id.* at 12-16.

[51] Entergy IB at 92-95.

[52] *Id.* at 98-99.

Bandwidth payment is fairly characterized as exclusively fuel and purchased-power related. The APSC also claims that if the Commission determines that Ameren should not pay the allocated $14.5 million share of Entergy Arkansas' Bandwidth payment, then the Entergy Arkansas ratepayers should not be required to pay any more than the retail energy ratio share of EAI's Bandwidth payments, which is the ratio of Entergy Arkansas' retail energy to Entergy Arkansas' total (retail and wholesale) energy.[53]

64. The LPSC, MPSC, and the CNO, essentially take no position on and offer no substantive analysis of this issue. ETEC's position is that the Ameren contract is different from its contract with Entergy and any decision in this case should not be binding on ETEC. According to the ETEC, its 2004 Agreement for Partial Requirements Wholesale Electric Service with EGSI explicitly permits the pass through of Bandwidth Payments receipts.[54]

65. The ETEC also claims that the Bandwidth Payments/Credits are energy related costs, which is why the Commission determined that they are best recorded in Account 555. Finally, the ETEC asserts that the Commission's decision with respect to the meaning of the 1999 Agreement between Ameren and Entergy Arkansas has no bearing on its contract with EGSI because the relevant terms of the two contracts are materially different.

66. The FERC Staff, in part, based upon the testimony of Staff witness John Sammon, agrees with Ameren and argues that the Ameren contract does not contain an adequate energy pass through provision. According to Staff's view, it is improper for Entergy Arkansas to allocate the cost of the Bandwidth payments to Ameren as Purchased Energy, through the contract.

67. The FERC Staff argues that even though the Commission's Order allows Entergy Arkansas to record Bandwidth payments in Account No. 555 and to record receipts in 447, both of which are the accounts in which purchased power and energy are recorded, this does not make them Purchased Energy expenses for purposes of the Service Agreement between Ameren and Entergy Arkansas.

68. However, Mr. Sammon also testified that it is reasonable to allocate total Bandwidth payments to wholesale requirements customers on the basis of the ratio of a customer's firm energy consumption to the total firm energy consumption for Entergy Arkansas, and that Ameren should reimburse Entergy on this basis.

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[53] APSC IB at 71.

[54] ETEC IB at 1-3.

D. The Nuclear Depreciation Issue

69. The LPSC claims that the nuclear unit service lives reflected in ETR-26 and ETR-28 are unjust and unreasonable because they do not accurately account for the remaining service lives of the units. The depreciation and decommissioning expenses of nuclear units should be calculated using the remaining service life of the unit.

70. Remaining service life refers to the estimated time that the facility will be in service from the present time to its estimated retirement date. Depreciation and decommissioning expenses are spread out and collected from ratepayers over the course of the remaining life of the unit. The question here is what should be the remaining service lives of Entergy's nuclear units for purposes of the Bandwidth calculation.

71. The LPSC asserts that since the Nuclear Regulatory Agency (NRC), has granted twenty year license extensions to nuclear units ANO 1 and ANO 2, the deprecation and de-commissioning expenses must follow this license extension and Entergy erroneously calculated the nuclear depreciation for these units in the Bandwidth formula. LPSC initially further contended that since Entergy has plans to request a twenty-year extension on the service lives of three other nuclear units in the near future and that the NRC will inevitably grant these requests, these units should reflect the proposed extension.

72. Given that remaining service lives should reflect the actual remaining useful life of the unit, the LPSC urged the Commission to exercise its power to extend the service lives to all of Entergy's five nuclear units to reflect sixty-year total service lives.

73. However, in its Initial and Reply briefs, the LPSC modified its position in accordance with the position of the FERC Staff, and now argues that the actual NRC granted license duration is the correct method for determining nuclear depreciation.[55] The change in the LPSC position is based upon the Commission's recent July 2, 2008 opinion in Docket No. EL08-50, wherein the Commission held that the nuclear depreciation expenses for the Grand Gulf nuclear unit should not be changed based upon an anticipated license extension by the NRC.[56]

74. The APSC urges the Commission to reject the LPSC's suggested extension

[55] LPSC IB at 38; RB at 25-26.

[56] *See Louisiana Public Service Commission System v. System Energy Resources Inc.* 124 FERC ¶ 61,003 (2008).

of the service lives of Entergy Arkansas' two nuclear units, ANO 1 and ANO 2.[57] According to the APSC, the Bandwidth formula is designed to equally divide production costs between the five Operating Companies. APSC alleges an extension of the ANO 1's and ANO 2's service lives will upset this balance and improperly burden EAI with approximately 58% of these expenses as opposed to the 20% burden that the Bandwidth formula contemplates.

75. Also, according to the APSC, the FERC's modification of depreciation and decommissioning rates is a *de facto* incursion on its province over such costs at the retail level because it will be forced to either accept the Bandwidth result or to change its rates to match. Additionally, if the APSC were to change its rates to match those set by the FERC, then the APSC would be faced with a retroactive rate problem, as these 2006 expenses have already been collected from ratepayers.[58]

76. Moreover, the APSC claims that the FERC's regulations require a detailed depreciation study which, neither the LPSC, nor any other party has yet submitted prior to any change in depreciation or decommissioning rates.

77. The MPSC asserts that there is no valid reason for changing the remaining service life of the Grand Gulf nuclear unit. The MPSC believes that if the Commission changes the remaining service lives of this unit, then it will be nearly impossible for it to recover the depreciation and decommissioning costs that it paid to SERI in 2006. According to the MPSC, once a rate has been established and approved by the FERC, or any other commission, revenues collected under those rates are valid until they are reset by the regulatory authority.[59]

78. Therefore, the MPSC urges the Commission to reject the LPSC's original request to speculatively increase the service life of the Grand Gulf unit to sixty years. According to the MPSC, any such change should be made *ex ante* and should be based on an extension of the NRC approved operating license.[60]

79. The CNO, Ameren and the ETEC take no position on and offer no substantive analysis of this issue.

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[57] APSC IB at 26-32.

[58] *Id*. at 35, 41-43.

[59] MPSC IB at 20-21.

[60] *Id*.

80. Entergy rejects LPSC's suggested extension of the service lives for its nuclear units. According to Entergy, ETR-26 and ETR-28 calculate depreciation and decommissioning expenses based on the service life data found in Form 1, and that is what it has done.

81. Moreover, Entergy claims Service Schedule MSS-3 requires the use of the depreciation expense found in FERC Form 1. If LPSC wants to adjust the source of this data, then Entergy contends that it must do so in the context of a Section 206 filing.

82. In addition, the purpose of the Bandwidth calculation is to roughly allocate Entergy's actual production costs among the Operating Companies. Given that Form 1 reflects the actual costs incurred by the Operating Companies, the use of any other source of data would fail to further this objective.

83. Finally, Entergy infers there is a jurisdictional problem with the LPSC's and Staff's suggestion to use data other than that found in the FERC Form 1. First, Entergy infers the FERC does not have the authority to require Retail Regulators to change their depreciation and decommissioning expenses.

84. Thus, if the Bandwidth calculation's depreciation and decommissioning expenses deviate from the Form 1 data, which reflects the rates as set by the Retail Regulators, then the FERC will not be able to order the retail regulators to adjust their nuclear expenses to match. If there are two sets of depreciation and decommissioning expenses, then the Retail Regulators will have a strong incentive to "trap" depreciation and decommissioning costs by not permitting Entergy to include these costs in its retail rates.

85. Second, there will be practical problems of an administrative and bookkeeping nature, requiring Entergy to keep two sets of books.

86. The FERC Staff agrees with the LPSC that the nuclear depreciation and decommissioning expenses used in Entergy's Bandwidth calculation are unjust and unreasonable. Staff argues these expenses are unjust and unreasonable because they are inconsistent among the various states and because they fail to comply with the Commission's stated policy, which requires that nuclear depreciation and decommissioning expenses be based on service lives that are consistent with the NRC approved operating licenses.[61]

87. Staff interprets the Service Schedule MSS-3 tariff as reserving for the Commission the power to set the depreciation expenses of these nuclear units for

[61] Staff IB at 30.

purposes of the Bandwidth calculation. Staff urges the Commission to exercise this authority to establish nuclear depreciation and decommissioning expenses based on service lives that reflect the units' current NRC operating license, as required by Commission precedent.[62]

88. Finally, Staff believes that Entergy Arkansas' decommissioning costs for ANO 1 and ANO 2 should not be set to $0 because this suggestion was based on out-of-date analysis.

E. Net Area Load Issue

89. The LPSC opposes Entergy's use of Form 1 data to calculate the variable energy ration (ER) for the 2006 Bandwidth compliance filing. According to the LSPC, ETR-26 and ETR-28 used sales data from the Intra-System Bills (ISB) to populate the calculations of ER, and Opinion Nos. 480 and 480-A require Entergy to follow this example in the 2006 compliance filing. Furthermore, the LPSC disagrees with Staff's position that the Commission's acceptance of Entergy's 2006 compliance filing effectively changed the approved "methodology" from ETR-26 and ETR-28.[63]

90. According to the LPSC, Entergy gave little to no notice of its intention to deviate from the approved methodology, and it should not now be rewarded for its deception. The LPSC believes that if Entergy is permitted to make this unilateral change it will only encourage future filings to make subtle, unannounced changes to the methodology in the hopes that the Commission will not notice.[64]

91. The APSC supports Entergy's use of Form 1 data to calculate ER. According to the APSC, Form 1 data is the correct method because it does not include opportunity sales, which eliminates a mismatch that exists when ISB data is used. Ultimately, the APSC concurs with Entergy and Staff that cost of service calculations should either (1) deduct opportunity sales revenues from the operating companies' production cost and simultaneously deduct opportunity sales energy and demand from the operating companies' energy (MWh) and demand (MW); or (2) make neither deduction.[65]

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[62] *Id*. at 35-36.

[63] LPSC IB at 12.

[64] *Id* at 18.

[65] APSC at 12-13.

92. Finally, the APSC notes that Service Schedule MSS-3 defines ER as "Each Company's Annual Energy (Net Area Requirements less Non-Requirements Sales for Resale) Divided by the Sum of all Companies Annual Energy (Energy Ratio)," which runs counter to the methodology reflected in ETR-26 and ETR-28. The APSC contends that Service Schedule, MSS-3 as the tariff, should control the issue and that the use of FERC Form 1 data is therefore appropriate.

93. The MPSC, the CNO, Ameren, and the ETEC take no position on and offer no substantive analysis of this issue.

94. Entergy asserts that FERC Form 1 data should be used to populate the calculation of ER. According to Entergy, using ISB data to calculate net area load in the Bandwidth formula creates a synchronization error because ISB data includes non-requirements sales while the Bandwidth formula excludes the costs associated with these non-requirement sales through the use of revenue credits from the Operating Company's total production costs. By contrast, FERC Form 1 data does not include non-requirements sales, thereby curing the synchronization error.[66]

95. Furthermore, Entergy claims that Service Schedule MSS-3 controls the issue, as opposed to Exhibits ETR-26 and ETR-28, and that Service Schedule MSS-3 permits the use of FERC Form 1 data.[67] Entergy estimates that the use of ISB data in this compliance filing with its synchronization error would require an incorrect increase of approximately $21 million in payments from Entergy Arkansas to the other Operating Companies.

96. Finally, Entergy notes that neither ETR-26 nor ETR-28 specifies the data source that should be used in the calculation of ER; rather, it only reflects the fact that ISB data was used in those exhibits because the FERC Form 1 data was not available at the time. It further argues that the FERC Form data was based upon ISB data to a large extent.

97. The FERC Staff disagrees with Entergy's claim that the source of data used to calculate ER in ETR-26 and ETR-28 is not part of the "methodology" as that term was used by the Commission in its recent order directing Entergy to make a Section 205 filing prior to deviating from the "methodology" found in ETR-26 and ETR-28. Therefore, though Staff recognizes that the use of ISB data leads to flawed results, it contends that Entergy should have made a Section 205 filing

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[66] Entergy IB at 10.

[67] *Id.* at 11-12.

prior to substituting FERC Form 1 data for ISB data.

98. However, Staff argues that the Commission's acceptance of Entergy's compliance filing, with its proposed amendment to the definition of ER in the Service Schedule MSS-3, elevated that amended definition to the level of a filed lawful rate, which holds precedence over any "methodology" conflict in ETR-26 or ETR-28.[68]

99. Consequently, the calculation of ER now requires the use of page 401a FERC Form No. 1 load data that Entergy used in its 2006 compliance filing and not the ISB data used in ETR-26 and ETR-28.

100. All parties recognize that use of the ISB data will create enormous errors and will skew the Bandwidth calculations.

F. Remaining Accounting Issues

1. Account 165/Net Operating Loss Carry Back Issue

101. This issue involves the proper accounting practice for a tax refund to be received in 2006 for a net operating loss carry back associated with Hurricanes Katrina and Rita, and whether those amounts should be included within the 2006 Bandwidth calculation?

102. The LPSC claims this account contains numerous errors. According to the LPSC, ETR-26 and ETR-28 included the total amount found in Account 165 in each Operating Company's Form 1 in the formula used to determine production costs, which in turn was used to calculate Bandwidth payments.[69]

103. These Account 165 amounts reflected the simple average of the beginning and end of the year balances as reported on the Form 1. However, in its May 29, 2007 compliance filing, Entergy adjusted the FERC Form 1 Account 165 amounts for Entergy Gulf States, Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans, to remove the effects of a tax net operating loss (NOL) carry back from 2005.

104. The LPSC asserts Entergy was required, but failed, to make a Section 205 filing prior to making any such adjustment to the Account 165 entry into the

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[68] Staff IB at 11.

[69] LPSC IB at 19.

Bandwidth calculation. The LPSC notes that the prior Account 165 entries were based on the simple average of the beginning of the year balance and the end of the year balance. The LPSC contends that it would now be inappropriate to allow Entergy to review the costs reported in the account and then "pick and choose" which entries to exclude.[70]

105. Finally, the LPSC also opposes Staff's claim that the NOL tax carry backs should have been booked to Account 143 (Other Accounts Receivable). According to the LPSC, Staff's position is without merit because it runs counter to the clear instructions of the FERC Uniform System of Accounts (USOA).[71]

106. The APSC supports Entergy's recording of the NOL carry backs as "Prepayments" in Account 165, but it also recognizes that the NOL carry backs could have been validly recorded as a receivable in Account 143, which is Staff's position.[72]

107. However, the APSC explains that in either event the NOL carry backs would not be included in the Bandwidth calculation. Irrespective of the accounting issues, the APSC urges the Commission to exclude the NOL carry backs from the Bandwidth calculation because (1) the storm damage at issue resulted in negligible, if any, damage to production facilities and (2) the NOL carry backs relate to damages caused by a storm that occurred in 2005, which means that they should not be included in the 2006 Bandwidth calculation.

108. Though the MPSC agrees with Staff that the NOL carry backs are more appropriately recorded in Account 143 as a receivable, it contends that its inclusion in the Bandwidth calculation should rest solely on the relation of the damage caused by Hurricanes Katrina and Rita to the production function. The MPSC argues that Entergy's exclusion of the NOL carry backs was appropriate and did not require a Section 205 filing because Entergy is not bound to follow the examples in ETR-26 and ETR-28 where such adherence would lead to the inclusion of costs that are clearly not related to production.[73]

109. According to the MPSC, approximately 95% of the damages caused by

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[70] *Id*. at 21.

[71] *Id*.

[72] APSC IB at 6-7.

[73] MPSC IB at 8.

Hurricanes Katrina and Rita, which are the impetus for the NOL carry backs, were to transmission and distribution, which are not costs that are included in the Bandwidth calculation. Furthermore, the MPSC notes that the NOL carry backs did not even exist at the time ETR-26 and ETR-28 were prepared. Therefore, there is no reason to reflect the NOL carry backs in the Bandwidth calculation.[74]

110. The CNO claims that the NOL carry backs are not prepayments in the strict sense of the word as defined in the FERC USOA. Rather, the CNO contends that they are receivables that Entergy should have recorded in Account 143 when Entergy was certain to receive them. Given that the amounts in Account 143 are not included in the Bandwidth calculation, the CNO ultimately agrees with Entergy and APSC that the NOL carry backs were appropriately excluded from the Bandwidth calculation.[75]

111. Ameren and the ETEC take no position on and offer no substantive analysis of this issue.

112. Entergy claims that the NOL carry backs were properly recorded in Account 165 as Prepayments. According to Entergy, the NOL carry backs are solely related to damages caused by Hurricanes Katrina and Rita and as such, are not properly included in the Bandwidth calculation.

113. The FERC Staff asserts that Entergy improperly accounted for the NOL carry backs. According to Staff, the FERC USOA dictates that these amounts should have been recorded in Account 143 as “Other Account Receivable.” Furthermore, Staff does not view the charge to Account 143 as a deviation from the methodology in ETR-26 and ETR-28, which would require a Section 205 or 206 filing.[76]

114. Rather, Staff considers this an accounting error that should be corrected in this proceeding. However, regardless of whether the amounts are recorded in Account 165 or in Account 143, Staff agrees with Entergy that these amounts should not have been included in the Bandwidth calculation.

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[74] *Id*. at 8-9.

[75] CNO IB at 9-13.

[76] Staff IB at 13-17.

2. Hurricane Storm Recovery

115. This issue involves the proper accounting practice relating to Hurricanes Katrina and Rita storm damage costs, recoveries, related regulatory assets and regulatory liabilities, and how these various costs and recoveries should be reflected in the 2006 Bandwidth calculation?

116. According to the LPSC, Entergy Gulf States and Entergy Louisiana, improperly booked certain administrative and general (A&G) expenses as a regulatory liability in Account 254, which is not included in the Bandwidth calculation. The LPSC insists that the FERC USOA required these expenses to have been booked in Account 924 and functionalized to production for inclusion in the Bandwidth calculation.[77]

117. The LPSC claims that Entergy's accounting "methodology" for these expenses deviates sharply from its historic and "normal" storm damage accounting and directly contradicts the instructions found in the FERC USOA.[78]

118. The LPSC argues that if Entergy Gulf States and Entergy Louisiana wished to deviate from the methodology of ETR-26 and ETR-28, they should have first made a Section 205 filing.[79]

119. According to the APSC, the proper accounting for the storm cost deferral and recovery approved by Retail Regulators was to transfer these deferred costs and recoveries from Account 228.1 to Account 182.3 (Other Regulatory Assets). The APSC claims that the Retail Regulators' approval of this deferral and recovery changed the very nature of the asset from a cost deferral to a customer revenue stream, necessitating the recordation of this revenue stream as a regulatory liability in Account 182.3.[80]

120. Moreover, the APSC urges the Commission to exclude the storm damage costs from the Bandwidth calculation because (1) it is unlikely that much, if any, of the storm damage costs can be functionalized to the production function that is the sole focus of the Bandwidth calculation; (2) the storms that gave rise to these costs occurred in late August and early September 2005, which is outside of the

[77] LPSC IB at 25-56.

[78] *Id.*

[79] *Id.*

[80] APSC IB at 20.

2006 test period; and (3) it is unfair, inequitable and unduly discriminatory to export storm costs to another state via the Bandwidth calculation.

121. In addition, the MPSC argues that the regulators' approval of storm cost deferral and interim recovery required Entergy Gulf States and Entergy Louisiana to establish a regulatory asset, which it did. The MPSC asserts that this regulatory asset was and should have been amortized to a regulatory expense account as the revenues are collected and reflected in the Company's records, but these excess losses were not, and should not have been, expensed to Account 924 because the recovery is not the recovery of property insurance.

122. Rather, the MPSC insists that it is the recovery of a regulatory asset that is the excess storm damage losses over reserves authorized by the regulator. The only amount that is expensed to Account 924 is the previously authorized accrual for property insurance. Thus, the MPSC agrees with Entergy's accounting of the storm damage costs and interim recoveries.

123. Furthermore, the MPSC claims that none of the cost accumulated in Account 228.1 and charged to Account 924 should be included in the Bandwidth calculation. According to the MPSC, these amounts were collected to self-insure Entergy's transmission and distribution system, but they have no relation to production. As such, the MPSC contends that these accounts reflect transmission distribution costs, which should not be included in the Bandwidth calculation, which exists to equalize only production costs.[81]

124. According to the CNO, Entergy Gulf States and Entergy Louisiana improperly recorded the approved interim storm damage recoveries as a regulatory liability in Account 254, thereby reflecting the fiction these Operating Companies would be required to return this money as an offset against final recoveries.

125. The CNO also claims that Entergy Gulf Sates and Entergy Louisiana improperly recorded the interim recoveries received as regulatory debits in Account 407.3, which ultimately excluded all storm damage costs from the Bandwidth calculation.

126. The CNO asserts that Entergy Gulf States and Entergy Louisiana should have recorded the interim recoveries as regulatory assets in Account 182.3 because there was no real possibility that they would have been called upon to return any of the interim recoveries.[82]

[81] MPSC IB at 12-13.

[82] CNO IB at 19, 23-24.

127. In fact, the order that authorized the interim recoveries expressly recognized that they only reflected a portion of the total recoveries that would be granted through permanent rate increases. In addition, the FERC USOA required Entergy Gulf States and Entergy Louisiana to spread the interim recoveries as they were received through the appropriate operation and maintenance accounts that corresponded to the facilities/assets that were damaged by Katrina and Rita.

128. Ameren and the ETEC take no position on and offer no substantive analysis of this issue.

129. Entergy insists that it properly followed the FERC USOA when it accounted for the Hurricane Katrina and Rita storm damage costs. According to Entergy, there was nothing in the Retail Regulators' interim orders that permitted an additional accrual to Account 924, as suggested by the LSPC. Rather, the Retail Regulators' orders authorizing interim recovery were by their very nature subject to refund, which is a fact that necessitated booking these accruals to Account 254 with a corresponding offset to account 407.3.[83]

130. Despite the LPSC's claim, Entergy asserts that it did not deviate from either normal accounting practices or from its historical method of accounting for storm damages. Furthermore, Entergy asserts that its accounting of storm damages did not deviate from the methodology found in ETR-26 and ETR-28.

131. Entergy also disagrees with the CNO's claim that the storm expenses should have been spread through a variety of expense accounts to facilitate recovery through base rates because in 2006, the Retail Regulators had not authorized such recovery. In addition, Entergy notes that if it were to account for storm damages in the manner suggested by Staff, then there would not be any change to the amounts included in the Bandwidth calculation.[84]

132. Consequently, Entergy urges the Commission to find that none of the storm damage costs or the interim recoveries are includible in the 2006 Bandwidth calculation.

133. Staff disagrees with the LPSC claim that Entergy should have deferred storm costs in Account 228.1. Staff claims that Entergy should have charged the storm damage costs that exceed Account 228.1 to the appropriate operating and maintenance (O&M) expense accounts, and then, if it is probable that these excess costs are recoverable in future rates, Entergy should have credited the applicable

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[83] Entergy IB at 16-17.

[84] *Id*.

expense accounts and debited Account 182.3 (Other Regulatory Assets). Staff also disagrees with how Entergy Gulf States and Entergy Louisiana booked the interim storm recoveries.[85]

134. According to the FERC Staff, Account 254 should only be used to reflect amounts collected from ratepayers that are expected to be refunded in future rates. In this case, Staff claims that once the regulatory asset was created, Entergy Gulf States and Entergy Louisiana should have reflected the interim recoveries as reductions of that regulatory asset in Account 182.3 and then amortize the amount to the proper O&M expense account. Staff does not claim that any of these changes would alter the output of the Bandwidth calculation as filed by Entergy[86].

3. ADIT Amounts

135. This issue involves what accumulated deferred income tax (ADIT) amounts should have been included for the 2006 Bandwidth Calculation?

136. The LPSC contends that Entergy's removal of ADIT balances from the 2006 Bandwidth filing violated Opinion No. 480 as well as the Commission's compliance order because it deviated from the methodology found in ETR-26 and ETR-28.[87] According to the LPSC, ETR-26 and ETR-28 only included "two adjustments to the ADIT amounts in Account 190.[88]

137. One was to remove SFAS 109 ADIT amounts, and the other, the property insurance reserve ADIT for Entergy Arkansas.[89] The LPSC asserts that contrary to Entergy's belief, the Service Schedule MSS-3 tariff language does not give Entergy the authority to selectively choose which amounts of ADIT to remove from the Bandwidth calculation.[90]

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[85] Staff IB at 22-28.

[86] *Id*.

[87] LPSC IB at 35.

[88] *Id*.

[89] *Id*. at 35-36.

[90] *Id*. at 37.

138. Ultimately, the LPSC asserts that Entergy's removal of ADIT deviated from the ETR-26 and ETR-28 methodology and from the instruction found in the tariff, and therefore, the LPSC urges the Commission to disallow this removal.[91]

139. The APSC, CNO, Ameren, and ETEC take no position on and offer no substantive analysis of this issue.[92]

140. The MPSC supports Entergy's removal of the ADIT balances in Account 190, which are now being challenged by the LPSC.[93] According to the MPSC, the Service Schedule MSS-3 tariff "allows for the removal of the balances which are 'not generally properly includable for FERC cost of service purposes, … and ADIT amounts arising from retail ratemaking decisions.'"[94]

141. The MPSC asserts that Entergy properly removed certain ADIT balances pursuant to this exclusion, and it disagrees with the LPSC's claim that the removal was improper because it deviated from the ETR-26 and ETR-28 methodology.[95] Turning to the LPSC's argument, the MPSC notes that the Commission "approved the Service Schedule MSS-3 compliance tariff containing the 30.12 ADIT provision as being in compliance with ETR-26 and 28," which made it the lawful rate under the filed rate doctrine.[96]

142. Thus, the MPSC believes that it, and not ETR-26 and ETR-28, controls this issue.[97] Furthermore, the MPSC claims that "some of the excluded balances that are properly excluded from the Bandwidth calculation did not even exist when the Commission adopted ETR-26 and ETR-28," which would necessarily mean that they were not accounted for in ETR-26 or ETR-28.[98]

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[91] *Id*. at 38.

[92] APSC IB at 74; Ameren IB at 9; ETEC IB at i.; CNO IB at i.

[93] MPSC IB at 14.

[94] *Id*. (quoting Section 30.12 of the MSS-3 tariff).

[95] *Id*.

[96] *Id*. at 14-15.

[97] *Id*.

[98] *Id*.

143. Therefore, the tariff logically controls this issue, and each of the ADIT amounts removed were "not generally properly includable for FERC cost of service purposes" because they were either not related to the production function or were not included in wholesale or retail rates.[99]

144. According to Entergy, "Section 30.12 of the Bandwidth Formula in Service Schedule MSS-3 provides that certain types of ADIT amounts should be excluded from the Bandwidth Calculation."[100] Entergy claims that the LPSC failed to identify a single ADIT amount that was improperly removed from the Bandwidth calculation and that it should therefore be "rejected out of hand."[101]

145. Regardless, Entergy believes that it has fully explained why certain ADIT amounts were removed and demonstrated that they were removed in compliance with the terms of Section 30.12 of the lawfully filed and approved MSS-3 tariff.[102]

146. FERC Staff takes no position on and offers no substantive analysis of this issue.

147. Furthermore, the LPSC originally asserted and now, all parties agree, that the River Bend 30 unregulated ADIT should not be included in the production costs reflected in ETR-26 and ETR-28.

4. River Bend A & G Issue

148. This issue involves determining the method to properly remove the administrative and general expenses and other taxes, associated with the 30% share of the capacity of the River Bend nuclear facility prior to the functionalization of such costs in the 2006 Bandwidth calculation?

149. Entergy agrees it erroneously included the administrative and general (A&G) costs associated with the unregulated portion of the River Bend Nuclear Unit.[103] It proposes to correct this mistake by first removing the River Bend 30%

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[99] *Id*. at 15-18.

[100] Entergy IB at 18.

[101] *Id*.

[102] *Id*. at 18-19.

[103] Entergy IB at 26.

A&G costs from the total EGS A&G and then EGS's "residual A&G amount (i.e., the A&G that does not include River Bend 30%) is functionalized to production using a labor ratio that does not include the River Bend 30% labor."[104]

150. Similarly, Entergy proposes applying this correction to Other Taxes, "which suffers from a similar problem."[105] By contrast, the LPSC proposes "to first multiply the total A&G expense using a new, unused labor ratio, which does not remove the River Bend 30% labor" and then to subtract "the River Bend 30% A&G expenses."[106]

151. According to Entergy, the LPSC's proposal "is inconsistent with the methodology of the Bandwidth formula because it requires the use of two labor ratios for EGS-one labor ratio for allocating A&G costs, including the costs associated with the River Bend 30%, and a second labor ratio for other cost allocations in the formula."[107]

152. Thus, Entergy contends that the LPSC's "proposed method would require an amendment to the Service Schedule MSS-3 Bandwidth formula to add an additional labor ratio to be used to functionalize the A&G costs associated with the River Bend 30%."[108] Therefore, Entergy urges the Commission to adopt its proposed method of correction.[109]

153. The APSC, the MPSC, the CNO, Ameren, and the ETEC all seemingly recognize the error, but do not offer an opinion about the proper method for correction.

5. Account 923/Outside Services Employed

154. This issue involves whether certain costs were misclassified to Account No. 923, "Outside Services Employed" and, if so, if this impacts the 2006 Bandwidth calculation?

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[104] *Id.*

[105] *Id.*

[106] *Id.* at 27.

[107] *Id.*

[108] *Id.*

[109] *Id.*

155. The LPSC agrees with the FERC Staff's position on this issue and urges the Commission to order Entergy to "review the costs recorded in Account 923, (Outside Services Employed), reclassify them to the appropriate functional operation and maintenance expense account, or other accounts in accordance with the requirements of the USOA, re-file their Form 1s for 2006, and to re-compute the Bandwidth payments and receipts."[110]

156. According to the LPSC, the USOA generally requires that vendor charges "be recorded in functional O&M expense accounts rather than in Account 923, an A&G expense account."[111] However, the LPSC claims that Entergy ignored this requirement and erroneously recorded vendor charges in Account 923.[112]

157. The APSC, MPSC, CNO, Ameren, and ETEC take no position and offer no substantive analysis of this issue.[113]

158. In response to the FERC Staff's claim, Entergy reviewed the charges in Account 923 to determine if any were misclassified.[114] The review revealed that "of the approximately $62.4 million in charges to Account 923 in 2006, approximately $6.6 million could be assignable to an account other than Account 923."[115]

159. According to Entergy, the majority of these misclassifications were debatable judgment calls, but in an abundance of caution they were reclassified.[116] Entergy then recalculated the Bandwidth payments and receipts and determined that the effect of these misclassifications was negligible.[117]

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[110] LPSC IB at 56.

[111] *Id*.

[112] *Id*.

[113] APSC IB at 76; MPSC IB at 21; CNO IB at i; Ameren IB at 9; ETEC IB at i.

[114] Entergy IB at 25.

[115] *Id*.

[116] *Id*.

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

160. FERC Staff argues that Entergy misclassified costs to Account 923 that should have been recorded in the proper O&M accounts.[118] FERC Staff recognizes that Entergy reviewed the charges in Account 923 and discovered approximately $6 million worth of misclassifications.[119] However, FERC Staff is not convinced that Entergy's review "captured all necessary reclassifications."[120]

161. Therefore, FERC Staff urges the Commission to order Entergy to "(1) perform a thorough review of the amounts booked to Account No. 923, (2) correct the accounting for misclassifications discovered and any remaining misclassifications inappropriately recorded in Account No. 923 in the ledgers and in their 2006 FERC Forms No. 1, (3) submit the corrected versions to the Commission and (4) correct and submit revisions of the Bandwidth calculation to incorporate the accounting and FERC Form No. 1 reporting corrections."[121]

6. Spindletop Issues

162. This issue involves determining how should Entergy Gulf States' costs of acquiring the Spindletop Gas Storage Facilities and the Spindletop Gas Storage Facilities regulatory asset, have been accounted for and reflected in the 2006 Bandwidth calculation?

163. Spindletop is a leached salt storage cavern and related natural gas pipelines and equipment, located in Sabine, Texas. It's used as a physical hedge for reliability and pricing purposes, and it supplies the EGS Sabine and other EGS gas generating units. Entergy accounted for Spindletop's facility capital costs in Account 182.3 (Regulatory Assets) and included the amortization expense in Account 407.3 (Regulatory Debits). The LPSC claims that this is an improper accounting of facility capital costs that incorrectly excludes these costs from the Bandwidth calculation. Given its previous order to amortize the capital costs of the plant over its useful life and then to include these amortization costs in rate base, the LPSC considers such costs to be related to production. Consequently, if changes to ETR-26 and ETR-28 are permitted, these costs should be booked in the proper accounts and included in the Bandwidth calculation.

164. According to the APSC, Spindletop technically satisfies the requirements to

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[118] Staff IB at 46.

[119] *Id.*

[120] *Id.* at 47.

[121] *Id.*

be considered a utility plant in service and be included in the Bandwidth calculation. However, the real problem arises in the valuation of the facility. The USOA provides that a utility plant is valued at its original cost when first devoted to public service with any difference between original cost and the consideration paid recorded as an acquisition adjustment.

165. The problem here is that the payments were essentially made in installments over five (5) years. Though the "installment" problem is solved by discounting the installment capital payments with an explicit or implicit interest rate, the question still remains as to whether it went into "public service" prior to when EGS acquired it, and if so, what was its original cost when it was first devoted to public service.

166. Moreover, the APSC contends that the inclusion of the Spindletop facilities could adversely provide Retail Regulators an incentive to retrospectively revise its accounting estimates to achieve locally favorable Bandwidth results.

167. If the Commission decides to depart from ETR-26 and ETR-28 to include the Spindletop facility capital costs in the Bandwidth calculation, the APSC urges the Commission to limit Spindletop's asset value to its original cost when first devoted to public service, less accumulated depreciation.

168. The LPSC agrees with FERC Staff on this issue.[122] Accordingly, the LPSC believes that: "Account No. 501 should be debited for each year's amortization of the Spindletop regulatory asset" because Account 501's description includes references to expenses related to the unloading of fuel from the shipping media and the handling of that fuel until it enters the "first boiler plant bunker, hopper bucket, tank or holder of the boiler house structure."[123] Given that the Spindletop facility is used to transport and store fuel, the LPSC believes, like FERC Staff, that its amortization should be booked in Account 501.[124]

169. Furthermore, the LPSC supports FERC Staff's accounting suggestion because it believes that the Spindletop facility is unquestionably a production facility.[125] However, the LPSC recognizes that "the issue of whether the

[122] LPSC IB at 61.

[123] *Id*. (quoting FERC Staff witness Janice Nicholas S-12 at 16).

[124] *Id*.

[125] *Id*.

regulatory asset maybe included in the production investment on which a return is calculated would appear beyond the scope of this docket."[126]

170. The APSC believes that this issue is not currently before the undersigned because the Commission has ruled that the Spindletop adjustment proposed by the LPSC is inconsistent with ETR-26 and ETR-28 and has set the matter for hearing in Docket No. EL08-51-000.[127] However, should the undersigned reach this issue, the APSC supports Entergy's current accounting of the Spindletop facility.[128]

171. "Because the Spindletop regulatory asset was appropriately established through the use of Account 407.4, the appropriate account to use for the amortization of the regulatory asset is Account 407.3, Regulatory Debits …."[129] The APSC disagrees with Staff's and the LPSC's Account 501 recommendation because "Account 501 does not provide for capital-related costs, such as those included in the Spindletop regulatory asset[,]" and since the Spindletop regulatory asset could not have been established through Account 501, its amortization should not be booked to Account 501 as suggested by FERC Staff.[130]

172. Moreover, the APSC believes that it would be inappropriate to use Account 501 because "'[t]he net result of such accounting would be to reflect in a current period Account 501 amounts relating to both a current period and a prior period.'"[131]

173. Finally, the APSC contends that the Commission ruled in its order creating Docket No. EL08-51-000 that the Spindletop regulatory asset amortization may not be included in the 2006 Bandwidth calculation at issue in this case because it would constitute an impermissible deviation from ETR-26 and ETR-28.[132] Therefore, the APSC believes that this issue is clearly beyond the scope of this

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[126] *Id*. at 62.

[127] APSC IB at 56.

[128] *Id*.

[129] *Id*. at 57.

[130] *Id*. at 56-57.

[131] *Id*. at 57.

[132] *Id*. at 58.

proceeding.[133]

174. The MPSC, CNO, Ameren, and the ETEC take no position on and offer no substantive analysis of this issue.[134]

175. Entergy agrees that the issue of how the Spindletop regulatory asset should be reflected in the Bandwidth calculation is no longer before the undersigned in this proceeding.[135] According to Entergy, the Commission determined in its order creating Docket No. EL08-51-000 that the Spindletop regulatory asset cannot be included in the 2006 Bandwidth calculation.[136]

176. Turning next to the issue of how to account for the Spindletop regulatory asset, Entergy opposes the LPSC's and FERC Staff's account 501 recommendation "because the definition of Account 501 does not provide for capital-related costs, such as those included in the Spindletop regulatory asset."[137]

177. Entergy also argues that "the capital-related amounts collected through the fuel charge were fully refunded, thereby removing any effect of these costs on fuel."[138] Consequently, "the use of Accounts 407.3 and 407.4 is appropriate for recording the Spindletop regulatory asset and amortization thereof."[139]

178. The FERC Staff recognizes that the Commission has removed from this proceeding the issue of whether the Spindletop regulatory asset should be included in the Bandwidth calculation.[140] Moreover, FERC Staff believes that the inclusion of the regulatory asset in the Bandwidth calculation would be an impermissible

[133] *Id*. at 58.

[134] *See* MPSC IB at 21-22; CNO IB at i; Ameren IB at 9; ETEC IB at i.

[135] Entergy IB at 27.

[136] *Id*. at 27-28.

[137] *Id*. at 29-30.

[138] *Id*. at 30.

[139] *Id*.

[140] Staff IB at 50.

deviation from the methodology in ETR-26 and ETR-28.[141]

179. Turning to the accounting of the regulatory asset, FERC Staff agrees with Entergy Gulf States' recording of the Spindletop facility capital costs as a regulatory asset in Account 182.3, but it disagrees with EGS's amortization of that regulatory asset in Account 407.3.[142]

180. FERC Staff claims that because EGS purchased natural gas transportation and storage services from Spindletop, the costs of those services should have been initially recorded in Account 501, Fuel, and "[t]o the extent that the capital-related costs (*i.e.* credit payments) were to be recovered in future LPSC approved rates, Account No. 501 should then have been credited when the regulatory asset was established in Account No. 182.3" and then "debited for each year's amortization of the regulatory asset."[143]

181. In addition, FERC Staff disagrees with Entergy's assertion that Account 501 does not provide for capital-related costs.[144] To the contrary, FERC Staff argues that "Account No. 501 includes depreciation expenses, which are clearly capital-related and analogous to the amortization of this regulatory asset."[145] Furthermore, FERC Staff argues that Entergy "should have recorded the costs of acquiring the Spindletop Gas Storage Facilities in Account No. 114, Electric Plant Acquisition Adjustments, rather than Account No. 101, Electric Plant in Service," as it did.[146]

182. The MPSC, the CNO, Ameren, and the ETEC take no position on and offer no substantive analysis of this issue.

7. Waterford 3 Issue

183. This issue involves how ADIT relating to the Waterford 3 Sale/Leaseback should be allocated within the Bandwidth formula? This issue is now moot.

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[141] *Id.*

[142] *Id.* at 50.

[143] *Id.* at 51.

[144] *Id.* at 52.

[145] *Id.*

[146] *Id.* at 50, 54.

184. The LPSC initially urged the Commission to exclude the ADIT associated with the Waterford 3 capitalized lease. According to LPSC, Entergy's calculations of variable production rate base (VPRB) and fixed production rate base (FPRB) costs incorrectly include the Waterford 3 capitalized lease despite the fact that none of the nuclear depreciation ADIT amounts are related to the Waterford 3 lease.

185. Thus, the LPSC urged the Commission to remove the Waterford 3 lease from the computations of VPRB and FPRB. Finally, the LPSC argued that ETR-26 and ETR-28 do not control this issue because the inclusion of the Waterford 3 lease in the Bandwidth calculation resulted from Entergy's 2007 Section 205 filing.

186. Though the APSC technically agreed with the LPSC that the Waterford 3 lease should be excluded from the Bandwidth calculation, it believed that this flaw was incorporated into the approved Service Schedule MSS-3 tariff. As such, it initially argued that it should only be excluded if the Commission decides to revise Service Schedule MSS-3 to correct errors or oversights. Otherwise, the Commission should require the LPSC to make a proper Section 206 filing in another proceeding to propose this adjustment.

187. The MPSC, the CNO, Ameren, Staff and the ETEC took no position on and offered no substantive analysis of this issue.

188. Entergy initially contended that the LPSC's argument is actually a challenge to the filed tariff, Service Schedule MSS-3, and ETR-26's and ETR-28's method of functionalizing ADIT. Given that the LPSC did not present this argument in a Section 206 filing, Entergy urged the Commission to dismiss this claim. In fact, the LPSC did make a subsequent filing in Docket No. EL08-51-000 and Entergy decided in that proceeding not to oppose the LPSC's position.

189. With Entergy subsequently not opposing the LPSC's proposed Waterford Capital Lease amendment, the Commission directed Entergy to remove the Waterford 3 Capital lease amounts from the computations of the nuclear plant ratio and the production plant excluding nuclear ratio, effective March 31, 2008. All parties seemingly accept this disposition as a full settlement of this issue, and concede this issue is therefore now moot. Entergy will make such adjustments in accordance with the order.[147]

[147] *Louisiana Public Service Commission v. Entergy Services, Inc.*, 124 FERC ¶ 61,010 (2008).

8. Interruptible Load Issue

190. This issue involves whether "interruptible load" should be included in the data for determining the variable "DR" in the 2006 Bandwidth calculation?

191. The LPSC initially claimed that the amounts of energy purchased and sold to the “exchange” pursuant to Service Schedule MSS-3 are directly impacted by interruptible load. As such, if the Commission finds that it is unreasonable to include interruptible demands in the 12 CP (coincident peak) allocation factor, it should include an interruptible load adjustment to the DR variable used to allocate costs.

192. According to the APSC and the MPSC, the LPSC has not presented any new facts that would necessitate reconsideration of the Commission’s decision in EL07-52-000, which already rejected the LPSC’s interruptible load adjustment proposal. Consequently, this is an issue which has been fully adjudicated and should be dismissed.

193. The CNO, Ameren and the ETEC take no position on and offer no substantive analysis of this issue.

194. FERC Staff agrees with Entergy, the APSC and the MPSC, to again reject the LPSC’s interruptible load adjustment proposal. In its Reply Brief, LPSC acknowledges the prior decisions by the Commission and withdrew this issue. No party has objected or otherwise takes a contrary position.

V. <u>THE HEARING</u>

A. Background

195. The hearing in this matter took place from June 17, 2008 through July 3, 2008. Sixteen witnesses appeared over thirteen days of hearing, and provided live testimony for the following parties respectively, in addition to filing pre-filed testimony: Theodore Bunting, John Hurtsell, Frank Gallaher, Bruce Louiselle, and Michael Schnitzer testified for Entergy; Philip Hayet, Stephan Baron, and Lane Kollen for the LPSC; Dr. Keith Berry, David Helsby and Tyler Tibbetts for the APSC; Hugh Larkin testified for the MPSC; George Mathai for the CNO; and John Sammon, Janice Garrison-Nicholas and Kevin Pewterbaugh testified for the FERC Staff.

196. Additionally, several witnesses provided pre-filed testimony, but the parties waived cross-examination at the hearing, including: Sallie Ranier and George Bartlett for Entergy; Shawn Schukar for Ameren; Randy Futral for the

LPSC; and Robert Smith for the ETEC. The undersigned allowed the LPSC to introduce pre-filed exhibits pertaining to the former APSC witness Michael Majoros, whom APSC had withdrawn, and to cross-examine Mr. Mathai on the ANO One and ANO Two nuclear depreciation issue, although the CNO in Mr. Mathai's revised pre-filed testimony withdrew this issue from his consideration.

197. Some 361 Exhibits were admitted into evidence. The undersigned also granted the parties the opportunity to present additional oral testimony pertaining to the imprudence issue against Entergy. The LPSC presented testimony by Mr. Hayet and Mr. Baron. Entergy was permitted to present oral testimony in rebuttal through the additional testimony of Mr. Gallaher, Mr. Schnitzer, Mr. Hurtsell and Mr. Louiselle.

198. The witnesses' qualifications and background are briefly summarized below:

199. Frank Gallaher retired from Entergy in 2003, but continues to serve as an independent consultant. He has a Bachelor and Masters of Science degrees in Electrical Engineering from Mississippi State University. He also has an MBA and Juris Doctorate degrees from Mississippi College. He served in various engineering and top level management positions for Entergy since 1967, including Senior Vice President for Fossil Operations, Executive Vice President for Operations for all of the Operating Companies, and Group President, Chief Utility Operating Officer. His last position was President, Fossil Operations and Transmission.

200. Theodore H. Bunting, Jr. is Senior Vice President and Chief Accounting Officer for Entergy and its subsidiaries. He is responsible for the preparation of monthly financial reports, accounting entry oversight, preparation of certain regulatory filings, accounting policy and formulation, and administration of all accounting procedures and controls. Mr. Bunting has been employed by Entergy in various capacities for approximately twenty-five years. Mr. Bunting holds a Bachelor of Arts in Economics from Hendrix College and is a Certified Public Accountant.

201. Bruce M. Louiselle is an independent consultant with over thirty years of experience in the areas of public utility economics, finance, and accounting. Mr. Louiselle has participated in the preparation of electric, gas, and telephone rate structure reports and has testified in over 200 proceedings before both state and federal regulatory bodies, including the FERC. Mr. Louiselle holds a Bachelor of Arts degree in Economics and a Juris Doctorate, both from the George Washington University.

202. Michael Schnitzer is an independent consultant to Entergy. He is Director of North Bridge Group, Inc., located in Concord, Massachusetts. He has a Bachelors of Arts degree in Chemistry from Harvard University and a Masters degree in Business from the Massachusetts Institute of Technology. He specializes in management, planning and procurement issues involving electric utilities.

203. John Hurtsell is Vice President of Energy Management in the System, Planning and Operations Department, for Entergy. He has a Bachelor of Science degree in Mechanical Engineering from Louisiana State University and a Masters in Business Administration from the University of New Orleans. He has worked for Entergy in various engineering, planning and management positions since 1982.

204. Sallie Ranier is Entergy's Director of System Planning, Business, and Support and Regulatory Affairs Department. She has a Bachelor of Science degree in Engineering Technology from Louisiana State University and an MBA from Texas A&M University.

205. George Bartlett is Director of Transmission Operations for Entergy. He has a Bachelor of Science degree in Electrical Engineering from Tulane University. He is a registered engineer in the State of Louisiana.

206. Stephen J. Baron is the President of, and a principal with Kennedy and Associates. Mr. Baron has over thirty-years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning and economic analysis. He has previously testified on cost allocation issues in over 50 cases before the Commission. Mr. Baron holds a Bachelor of Arts degree in Political Science and a Master of Arts degree in Economics, both from the University of Florida.

207. Lane Kollen is Vice President and a principal with Kennedy and Associates, where he provides utility rate and planning consulting services. Mr. Kollen has over thirty-years experience in the utility industry, both on behalf of utilities and as an independent consultant, and has served as an expert witness in numerous proceedings before the Commission on planning, ratemaking, accounting, finance and tax issues including proceedings involving Entergy. Mr. Kollen holds a Bachelor and Master's degree in Business with an emphasis in accounting, both from the University of Toledo. He is a Certified Public Accountant and a Certified Management Accountant.

208. Philip Hayet is a consultant with Kennedy and Associates, from Roswell, Georgia. He is an Electrical Engineer, receiving his Bachelor of Science and

Masters degrees in Electrical Engineering from the Georgia Institute of Technology. He has extensive experience in the utility field.

209. Randy A. Futral is a Consulting Manager with the firm of Kennedy and Associates where he provides utility rate and planning consulting services Mr. Futral has over twenty years accounting experience and has provided consulting services to state government agencies and large consumers of utility services in ratemaking, financial, tax, accounting, and management areas. Mr. Futral holds a Bachelor of Business and Science degree with an emphasis in accounting from Mississippi State University.

210. Tyler D. Tibbetts is an independent consultant to electric, gas, and water utilities, governments and regulators. Mr. Tibbetts has over thirty-five years of consulting experience in the utility industry. Mr. Tibbetts has directed numerous cost assignment projects for utilities and has been responsible for a number of projects involving Entergy operating and service companies. Mr. Tibbetts holds a Bachelor of Arts in Accounting and Economics from Augustana College and is a Certified Public Accountant.

211. Dr. Keith Berry is a professor of economics and business at Hendrix, College, and a consultant and principal for the firm of Economic and Financial Consulting Group, Inc. He has a Bachelor of Arts degree in Mathematics from Hendrix College and a Doctorate in Economics from Vanderbilt University. He has extensive experience working on rate issues pertaining to utilities.

212. David T. Helsby is an independent consultant with R.W. Beck, Inc., from Mercer Island, Washington. He has a Bachelor of Science degree in Electrical Engineering from Washington State University.

213. Hugh Larkin, Jr. is a Certified Public Accountant from Livonia, Michigan. He graduated from Michigan State University in 1960, and has extensive accounting experience with electric utilities.

214. Robert Smith is Vice President of GDS Associates, a multi-discipline engineering and consulting firm. He has a Bachelor of Science degree in Industrial Management from the Georgia Institute of Technology. He specializes in consulting in utility rate issues.

215. Shawn Schukar is Vice president of Strategic Initiatives for Ameren. He has a Bachelor of Science degree in Mechanical Engineering and an MBA from the University of Illinois. He has over twenty three years experience in the public utility industry.

216. John K. Sammon is an Energy Industry Analyst in the Office of Administrative Litigation at FERC. Mr. Sammon is responsible for conducting technical analyses of electric rate matters in proceedings set for hearing before the Commission. He has been an employee of the Commission (and its predecessor, the Federal Power Commission) since 1973. Mr. Sammon holds a Bachelor of Engineering degree from City College of New York, a Master of Business Administration degree from the Bernard Baruch Graduate School of Business Administration and a Juris Doctorate from George Mason University School of Law.

217. Janice Garrison-Nicholas is Special Assistant to the Director, Office of Administrative Litigation. She has a Bachelor of Science degree in accounting from the University of Maryland, and is a CPA. She has over 30 years of experience at the FERC and in private practice.

218. Kevin Pewterbaugh is employed at the FERC as a petroleum engineer in the Office of Administrative Litigation. He has a Bachelor of Science degree in Petroleum and Natural Gas Engineering from the Pennsylvania State University, and has continuing education in the area of depreciation analysis.

219. George Mathai is a Certified Public Accountant. He has a Bachelor of Science degree in Business Administration and Journalism from Dallas Baptist University and a Master of Public Administration from New York University. He served in various auditing and management positions at the Oklahoma Corporation Commission over twenty-seven years. He is now a consultant with Legend Group Limited, in Denver, Colorado.

220. Michael J. Majoros is a consultant and principal with Snavely, King, Majoros, O'Connor and Lee, Inc., an economic consulting firm in Washington, D.C. He has a Bachelor of Science degree in Business Administration with an emphasis in accounting. He has experience in the area of public utility depreciation.

B. Summary

221. The undersigned notes that despite the application of various accounting rules and practices, the accounting practices used by Entergy to calculate the Bandwidth payments are in large part, a matter of judgment. Multiple witnesses testified regarding the accounting practices used by Entergy, with widely differing opinions. Mr. Tibbetts, Mr. Larkin, Mr. Mathai, Mr. Bunting, Mr. Schukar, Ms. Garrison-Nicholas, and Mr. Kollen, all provided some opinions pertaining to the appropriateness of Entergy's accounting practices.

222. As indicated, this proceeding involves the first annual filing required under the Commission's previously issued Opinions 480 and 480-A. This "Bandwidth filing" is calculated using production costs that were recorded in 2006. Entergy's Bandwidth filing's calculation establishes that Entergy Arkansas should make payments to the other Entergy Operating Companies in the amount of $251.7 million, in order to achieve rough cost equalization.

223. The calculations used in the May 29, 2007 filing reflect the additional adjustments approved by the Commission on March 30, 2007 (Exhibit No. ESI-6 at 23). The result of the filing is an approximate $251.7 million payment by Entergy Arkansas as follows: $40.577 million to Entergy Mississippi;$ 91.051 million to Entergy Louisiana; and $120.103 million to Entergy Gulf States. No payment is due Entergy New Orleans as its bus bar production costs were slightly below the system's average.

224. Ms. Sallie Ranier, Entergy's Director of System Planning Business Support and Regulatory Affairs, provides a general description of the Entergy System. (Exhibit No. ESI-3). Entergy Corporation is an electric holding company that at all relevant times consists of five retail electric companies and various support and services subsidiaries, including ESI. Each individual Operating Company owns its own generating and transmission assets. However, the Entergy System is planned and operated as a single integrated electrical system, pursuant to the "Entergy System Agreement."

225. The System Agreement establishes an "Operating Committee" that is charged with the responsibility for determining generation addition or acquisition plans that provide capacity to meet system load requirements and projections and which attempts to provide reliable services to customers at reasonable cost, consistent with sound business practice and operational constraints.

226. Ms. Ranier also provided valuable evidence pertaining to the various "Service Schedules" to the System Agreement that governs payments and receipts among the Operating Companies for different types of services (Exhibit No. ESI-4). Essentially, the Bandwidth filing is governed by Service Schedule MSS-3, which was approved to be used by the Commission in Opinion 480 (Exhibit No. ESI-4 at 44). In addition to Ms. Ranier's testimony, three additional witnesses for Entergy presented evidence supporting the calculations used in formulating the Bandwidth filing.

227. Mr. Theodore H. Bunting, Jr., Entergy Corporation's Senior Vice-President and Chief Accounting Officer, describes the accounting systems that Entergy has in place to ensure its books and records accurately reflect the production costs incurred by the Operating Companies, and that such procedures are in compliance

with the generally accepted accounting principles and the Commission directed USOA practices (Exhibit No. ESI-5).

228. Mr. John Hurtsell describes the process of how Entergy acquires and operates generation resources, including purchase of fuel and power, and how Entergy minimizes variable production costs consistent with maintaining system reliability. He reviews data demonstrating the amount of power from third parties Entergy purchased in 2006 (Exhibit No. ESI-20).

229. Mr. George Bartlett provides testimony as to how Entergy plans and operates its transmission system (Exhibit No. ESI-15). He further testified that Entergy invested $1.4 Billion from January 2000 through December 2006, in the Entergy transmission system. He further describes the process as to how Entergy pursued transmission projects that were identified to ensure anticipated production costs reductions could be achieved, by eliminating transmission constraints.

230. The main expert witness presented in support of the proposed filing by Entergy was Bruce M. Louiselle, President of "ECONAT, Inc.," a consultant (Exhibit No. ESI-6). His testimony displays an in-depth knowledge of the inner workings of how and why Entergy reached the current proposed calculations in the Bandwidth filing.

231. Mr. Louiselle provides an in-depth analysis of the components of and the actual inputs to the formula, and rebuts the main challenges alleging improprieties with the Bandwidth filing, by the LPSC and its main witness, expert Stephan Baron.

232. Mr. Louiselle provides precise explanations in primarily three key areas central to the issues raised by the protestors in this case. He describes the source of the data used to input the Bandwidth filing and the internal auditing processes used to test its accuracy. Mr. Louiselle also describes the regulatory review process involved with certain production costs pertaining to the individual jurisdictions of the five separate Operating Companies. Additionally, Mr. Louiselle describes the nature of the protests and attempts to rebut the protests allegations.

233. The Entergy's compliance filing quantified the disparities in the bus bar production costs for each Entergy Operating Company, and based upon the calculation, determined the payments and receipts for each Operating Company, consistent with the Bandwidth formula required by the Commission in Opinions 480 and 480-A. The bus bar production costs of an operating company include the allocated production function costs used to serve the "net area loads" of the company.

234. Mr. Louiselle further explains that generally the costs for running an electric utility fall into three areas: production function, transmission function and distribution function. Since this present proceeding pertains to the production costs, these bus bar costs would include all direct costs, fixed and variable, of the Operating Company's owned generating facilities, up to the "bus" or point of interconnection on the transmission grid. It includes the demand and energy costs associated with power purchase, indirect costs, such as administrative and general expenses, and the return of and in general all intangible plant functionalization costs.

235. The System Agreement is a Commission approved agreement that provides for and allocates among the participating Operating Companies, the benefits and costs of the coordinated operations of those companies, and provides seven service schedules which specify payments and responsibilities.

236. These service schedules provide rates to formulate the costs to be allocated. The System Agreement provides for a sharing of the cost of reserve capacity on the system. It further requires that the generating resources be economically dispatched throughout the system.

237. Service Schedule MSS-3 determines the cost of providing energy to the "Entergy Energy Exchange," which costs are paid by the separate Entergy Operating Companies that are allocated energy from the Exchange "Pool Energy."

238. The Commission in Opinions 480 and 480-A, requires that the bus bar production costs used in formulating the Bandwidth calculation pursuant to Service Schedule MSS-3, are to be calculated by reference to Exhibits ETR-26 and ETR-28, exhibits which were admitted in that earlier proceeding. Exhibit ETR-28 contains the derivation of the bus bar production costs for the twelve months ending August 31, 2002. Exhibit ETR-26 is a summary of the bus bar production costs analysis for each Operating Company for the years 1983-2002.

239. Mr. Louiselle was the author and authenticating witness for both documents. He described that the source of the data used to create the documents was primarily from FERC Form 1 for each company. However, he had made certain adjustments to the Form 1 data to reflect subsequent revisions to the fuel and purchased power costs as reported in the Intra-System Bills (ISB) and to remove certain abnormal and non-recurring results. At the time he prepared these exhibits, Mr. Louiselle did not anticipate they would be used in a tariff formula (Exhibit No. ESI-6).

240. He describes the following data which was used in the Bandwidth calculation, but was not taken from the FERC Form 1: Coal Mining Equipment

Plant in Service, Accumulated Depreciation & Operating Company Ownership Percentage; Co-owner portion of EAI's Fuel Inventory; Retail Ratemaking Accumulated Deferred Income Taxes in Accounts 190, 281, 282 and ADITC 3%; DAP Adjustment; River Bend 30% Adjustment; Decommissioning Expense as approved by Regulator; Cost of Capital pursuant to the terms of Service ScheduleMSS-3 tariff; Approved Common Equity Rate of Return as of December 31 of each year; Federal and State Income Tax Rates; Grand Gulf Accelerated Recovery Tariff (GGART) Adjustment for EAI and EMI; and, Demand Ratios of the Operating Companies (Exhibit No. ESI-6 at Table 2).

241. All of Entergy's witnesses, including testimony from former executive Frank Gallaher and expert consultant Michael Schnizter, address the imprudence issue.

242. The LPSC presented evidence through the testimony of several expert witnesses; Lane Kollen, Philip Hayet, Randy Futral, and Stephen Baron. These witnesses challenged all issues pertaining to Entergy's filing. In particular, the majority of the LPSC's evidence dealt with the imprudence issue.

243. The MPSC, through the testimony of Hugh Larkin, essentially sides with Entergy in most matters as does the APSC. The APSC does assert that if any claim of imprudence is found, the remedy should be borne by Entergy's shareholders. It relies upon the testimony of Dr. Keith Berry, David Helsby and Tyler Tibbetts.

244. Ameren asserts Entergy erroneously allocated to Ameren a portion of the Bandwidth payments owed by Entergy Arkansas. Through the testimony of Mr. Schukar, Ameren asserts the contract it has with Entergy does not authorize such an allocation. The CNO position is limited as it does not view itself as having any monetary stake in the outcome of this case, but wants to assure future filings meet proper accounting standards. It relies on testimony from George Mathai to support its position.

245. The ETEC position is also limited as it wants a determination that the Ameren 1999 Service Agreement does not impact its agreement with Entergy. It relies on the testimony of Robert Smith, which was not rebutted by any party in this proceeding.

246. In summary, the undersigned accepts the position of the FERC Staff that the proper legal methodology is Service Schedule MSS-3, but that ETR 26 and ETR 28 has continued applicability where the tariff does not address an issue. Furthermore, the undersigned finds that Entergy was not imprudent for not acquiring the ISES 2 capacity in 1996 and 1997; finds for Entergy pertaining to

the Ameren contract dispute; and finds that the nuclear depreciation rate used by Entergy in calculating the Bandwidth formula should reflect the actual granted license duration, currently in effect.

247. The undersigned further finds that Entergy properly calculated the net area load variable. The undersigned essentially finds with some corrections that Entergy utilized proper accounting practices under the circumstances. These corrections which include the proposed corrections to Account 923 and River Bend A&G as advocated by Mr. Louiselle, are accepted as the appropriate remedy.

248. The undersigned further agrees with the MPSC witness Mr. Larkin that Entergy should re-calculate and exclude any costs in Account 924 which is not related to production. The undersigned further finds the Ameren contract issue has no impact upon the ETEC contract.

VI. FINDINGS

A. Legal Effect/Methodology Issue

249. **ISSUE:** What is the legal effect of any deviation in either Entergy's Bandwidth filing in this docket or any proposed change to ESI's Bandwidth filing in this docket from: (a) the MSS-3 Bandwidth Formula Rate on file with the Commission; or (b) the methodology employed in Exhibits ETR-26 and ETR-28 in FERC Docket EL01-88?

250. The obvious effect of the ultimate decision in this proceeding will accordingly be reflected in any final adjustments made in the Bandwidth calculation to assure a just, reasonable, non-discriminatory, and non-preferential rate filing. The monetary significance in making readjustments to the Bandwidth formula may be significant as recognized by all parties, with a potential for Entergy Arkansas to make additional payments in the sum of approximately $75 million (Tr. at 347).

251. The parties seek the undersigned to map out the legal standard for not only this case but for future filings, and to set the precise methodology applicable, which is arguably outside the scope of the Commission' Order referring this case to hearing.

252. Entergy contends that the standard for evaluating the Bandwidth filing is whether it complies with the approved provisions of Service Schedule MSS-3, which now controls over the provisions set forth in ETR-26 and ETR-28, which the Commission has previously held should control the applicable methodology.

Entergy further acknowledges, however, that ETR-26 and ETR-28 should provide guidance to the extent that implementation details are not provided within Service Schedule MSS-3.

253. To the extent this determination is necessary and limited to the issues the undersigned must decide in this case, the undersigned finds the position advocated by the FERC Staff appears to be the position most consistent with what the undersigned finds to be the historical directives rendered by the Commission relating to what methodology should be used, and what standard should apply in this proceeding.

254. In essence, the FERC Staff argues that it believes the Service Schedule MSS-3 is the controlling methodology, but that ETR-26 and ETR-28 continue to control and are applicable where Service Schedule MSS-3 does not address an issue, in accordance with previous directives of the Commission.

255. The undersigned directly addresses this issue in this proceeding in deciding the variable net load issue and the definition of the Energy Ratio (ER), used to determine average variable production costs. By order dated August 15, 2008, the Commission in Docket No. ER-774-000 and ER08-774-0001, ordered this precise issue to settlement and hearing.[148] That proceeding arose from a proposed amendment filed by Entergy on April 1, 2008 to more clearly define the "ER" variable, apparently out of an abundance of caution, stemming from the LPSC's protest in this proceeding.[149]

256. Entergy seeks an amendment to Section 30.13, Service Schedule MSS-3, pertaining to the calculation of ER. Entergy proposes to permit use of the FERC Form 1 data to calculate ER. The ER variable is inextricably linked to the Revenue Credit variable, which results from the revenue received from customers outside the Operating Companies' net area for production service.

257. Since Entergy's proposed amendment wasn't filed until April 1, 2008, and is expected to be applied only prospectively, the Commission's Order referring Docket ER08-774-000 and 001 to settlement and hearing, does not render moot the net load variable issue in this proceeding, pursuant to the May 29, 2007 filing. Obviously, the Commission is free to disagree with this finding and disregard any determinations made by the undersigned.

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[148] *Louisiana Public Service Commission v. Entergy Services, Inc.*, 124 FERC ¶ 61,163 (2008).

[149] Entergy filed its second annual Bandwidth filing on May, 30, 2008, which has also now been ordered to settlement and hearing procedures.

258. With this procedural prospective, the undersigned agrees with the position of the FERC Staff that Entergy's definition of variable "ER" was accepted by the Commission in an amendment to Service Schedule MSS-3, in a prior filing (discussed more fully below in the "variable net load" issue), and is therefore now the lawful rate, and takes precedence in any conflict with the methodology found in ETR-26 and ETR-28, but that ETR-26 and ETR-28 continue to control where Service Schedule MSS-3 does not address an item, and ETR 26 and ETR 28 does, although the undersigned views this will be a rare occurrence, if at all.

259. The undersigned disagrees with Entergy that ETR-26 and ETR-28 are not controlling with respect to other issues, and are now reduced to only discretionary guidance. The undersigned adopts the FERC Staff believes that Entergy must make a Section 205 filing, to deviate from following the methodology set forth in the ETR-26 and ETR-28, with respect to "other areas," not covered by Service Schedule MSS-3, but expressly covered by ETR 26 and ETR 28.

260. The undersigned recognizes Entergy's position that there are obvious deficiencies in some situations with a rote application of ETR-26 and ETR-28, as the evidence in this proceeding shows that these documents were originally not intended to be used as a framework for establishing a tariff, and do not accurately relate to some of the underlying cost evaluations involved in calculating the Bandwidth formula. An example being the variable net load issue which if literally followed in this case, would result in substantial incorrect calculations.

262. Further recognizing that the exercise of good judgment is critical in calculating the Bandwidth formula and that it may be presumed that the Commission intended in its previous directives to assure Entergy made correct and fair calculations to achieve rough production cost equalization, the undersigned nevertheless agrees with the FERC Staff position that previous directives from the Commission requires Entergy should seek to amend any patent deficiencies it discovers when applying ETR-26 and ETR-28.

B. Imprudence Issue

263. **ISSUE:** Were the 1996 and 1997 decisions not to exercise EAI's option to purchase ISES 2 capacity imprudent? If it is found that the 1996 and 1997 decisions not to exercise Entergy Arkansas' option to purchase ISES 2 capacity were imprudent what is the remedy and/or what adjustments should be made to the 2006 Bandwidth calculation?

264. The undersigned finds Entergy was not imprudent.

1. Background

265. In the 1970s, the Entergy system was almost entirely based upon oil and gas-fired generation. Due to high gas and oil prices and federal laws curtailing construction of gas-fired units, Entergy expanded into nuclear and coal-fired generating units (Exhibit No. S-1; Exhibit No. S-18).

266. The Independence Steam Electric Station Unit No. 2 (ISES 2) is an 842 MW coal-fired electric generation unit that was placed in service in 1984, and which was operated by Entergy Arkansas.[150]

267. In 1988, the Grand Gulf nuclear plant came on line at higher than expected cost projections (Exhibit No. S-1; Exhibit No. S-18). Grand Gulf is owned by SERI, an Entergy affiliate. In Commission Opinions 234[151] and 292,[152] the Commission ruled that each Operating Company should get an allocated share of output pertaining to Grand Gulf so as to maintain rough production cost equalization among the Operating Companies.

268. The Commission assigned Entergy Arkansas a 36% share of the output of SERI's share of Grand Gulf (Exhibit S-1; Exhibit S-18). However, when Grand Gulf came on line, load growth on the Entergy system had fallen, gas had become cheaper and more plentiful, and federal restrictions on constructing gas-fired generation units eased (Exhibit No. S-18 at 19).

269. Therefore, in 1990, Entergy Arkansas "sold its 265 MW share of ISES 2, along with a 100% share of the gas-fired Ritchie Unit 2, to EPI."[153] Under the terms of that sale, EAI maintained a right of first refusal to repurchase the ISES 2 capacity at net depreciated value.[154] Moreover, the terms of the sale required that the capacity could not be used outside of Arkansas, without the APSC's prior consent. Under these terms, the APSC approved this sale.[155]

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[150] Entergy IB at 35.

[151] *Middle South Energy, Inc.*, 31 FERC ¶ 61,305 (1985); also at n.18.

[152] *Mississippi Industries v. FERC*, 814 F.2d 773 (D.C. Cir 1987); also at n.28.

[153] Entergy IB at 35.

[154] *Id.*

[155] *Id.*

270. Soon after, the CNO filed a complaint with the Commission alleging Entergy Arkansas' sale of its share of ISES 2 and other gas-fired unit capacity would negatively impact the New Orleans ratepayers (Exhibit No. S-18 at 19-21).

271. The LPSC joined in that complaint.[156] After a hearing, the Commission issued Order No. 386, essentially finding that Entergy's decision making process was flawed.[157] Order No. 386 also described what Entergy should have done during the decision making process, but the Commission made no determination as to whether Entergy was imprudent.[158]

272. In 1996, EPI decided to sell 180 MW of its ISES 2 capacity. In accordance with the terms of the 1990 contract, EPI first offered the capacity to Entergy Arkansas at net depreciated book value.[159] On April 3, 1996, EPI sent a letter to Entergy Arkansas offering to sell it 180 MW of ISES 2 capacity at $450/kW, which came out to a total price of over $80 million.[160] According to Entergy, Entergy Arkansas' staff determined "that it would cost more to acquire and operate ISES 2 than it would to meet Entergy's load requirements using the alternative resources …."[161]

273. Entergy also contends that at the time Entergy Arkansas was concerned that "impending retail competition and the potential for increased cogeneration made it likely that Entergy would lose significant amounts of its retail load, and that such losses of load would render an expensive capacity acquisition such as ISES 2 even more uneconomic.:"[162] Based on these concerns and its analysis of the potential costs and benefits of acquiring the ISES 2 capacity, Entergy Arkansas determined

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[156] *Id.*

[157] *City of New Orleans v. Entergy Corp.*, 65 FERC ¶ 61,333 (1993).

[158] *Id.*

[159] Entergy IB at 36.

[160] *Id.*

[161] *Id.*

[162] *Id.*

that it "should not exercise its purchase option for the ISES 2 capacity."[163]

274. EPI then attempted to sell the ISES 2 capacity to its existing co-owners as well as to other third parties.[164] Eventually, EPI was able to sell a little less than half of the ISES 2 capacity to the City of Jonesboro, Arkansas.[165] According to Entergy, the City of Jonesboro enjoyed "tax-advantaged financing not available to Entergy Arkansas or any other investor-owned utility that effectively allowed it to pay a higher price for the ISES 2 capacity."[166]

275. Then, in 1997, EPI reached agreement to sell some, but not all, of its remaining ISES 2 capacity to ETEC.[167] EPI again offered EAI an opportunity to exercise its right of first refusal.[168] But Entergy Arkansas again refused to exercise its right, determining "that the capacity would not be beneficial based on essentially the same grounds as in 1996."[169] Entergy again claims that ETEC, like the City of Jonesboro, was able to pay the inflated price for ISES 2 because it enjoyed "tax-advantaged financing not available to EAI."[170]

276. The LPSC is now challenging the prudence of Entergy Arkansas' decisions in 1996 and 1997 to not exercise its right of first refusal to acquire the ISES 2 capacity.

2. Legal Standard

277. The case law is very clear that there must be sufficient evidence to establish a claim of imprudence. Generally, utility management is presumed to have acted prudently.[171]

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[163] *Id*. at 37.

[164] *Id*.

[165] *Id*.

[166] *Id*.

[167] *Id*.

[168] *Id*.

[169] *Id*.

[170] *Id*. at 38.

278. It is only when a party in the proceeding creates "serious doubt" as to the prudence of an expenditure that the burden shifts and the applicant has the burden of dispelling those doubts and proving the questioned expenditure to have been prudent.[172] The Commission adopted the above holdings and further announced the following clarifying prudence standard:

> We reiterate that managers of a utility have broad discretion in conducting their business affairs and in incurring costs necessary to provide services to their customers. In performing our duty to determine the prudence of specific costs, the appropriate test to be used is whether they are costs which a reasonable utility management (or that of another jurisdictional entity) would have made, in good faith, under the same circumstances, and at the relevant point in time. We note that while in hindsight it may be clear that a management decision was wrong, our task is to review the prudence of the utility's actions and costs resulting there from based on the particular circumstances existing either at the time the challenged costs were actually incurred, or the time the utility became committed to incur those expenses.[173]

279. In this case, the LPSC counsels, extremely skilled litigators, presented a forceful case which questioned multiple decisions, judgments and actions on the part of Entergy over a twenty-four year period, arguing upon inference that a three hour rolling blackout, which occurred in July 1999, could have been prevented had ISES 2 been obtained, and that rates would have been lower in subsequent years.

280. However, in the final analysis the undersigned finds that the actual decision by Entergy not to obtain the ISES 2 capacity was not imprudent at the time it was made. It is also significant that the position of the FERC Staff is un-

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[171] *West Ohio Gas Co. v. Public Utilities v. Commission of Ohio*, 294 U.S. 63, 73 (1935); *Missouri ex rel. Southwestern Bell Tel. Co. v. Public Service Commission*, 262 U.S. 276 (1923); *Trunkline LNG CO.*, 45 FERC ¶ 61,256 at 61,775 (1988); *City of New Orleans v. Entergy Corp*., 61 FERC ¶ 63, 007 at 65,006 (1992), aff'd sub nom. New Orleans v. FERC, 67 F. 3d 947 (D.C. Cir. 1995); *Yankee Atomic Electric Co*., 65 FERC ¶ 63, 001 at 65, 003 (1993), aff'd in pertinent part 67 FERC ¶ 61, 318 (1994).

[172] *Kentucky Utilities Co.*, 62 FERC ¶ 61,097 at 61,698 (1993).

[173] *New England Power Co.*, 31 FERC ¶ 61,047 at 61,084 (1985); *aff'd. sub.nom. Violet v. FERC,* 800 F. 2d 280 (1st Cir. 1986).

categorically that Entergy was NOT IMPRUDENT in this case (Tr. at 2134 {Gilmore}).

3. The Evidence Supports Entergy's Position That It Was Not Imprudent

i. The LPSC Failed To Raise Serious Doubts

281. The undersigned finds that the LPSC failed to raise serious doubts about the prudence of Entergy's decision not to repurchase ISES 2 capacity in 1996 and 1997. At best, the LPSC's case supports a belief that looking at the issue from hindsight, Entergy may have benefited from the 1996 acquisition of ISES 2 capacity. The LPSC's argument is rooted primarily in its PROMOD Analysis.

282. The LPSC presented extensive evidence primarily through the testimony of Mr. Baron and Mr. Hayet, and by introducing a computer modeling program, which studied the cost effectiveness of acquiring the ISES 2 capacity and allegedly reflected savings of up to $23 million over the period 1997-2016. Mr. Hayet applied this analysis to the 2006 Bandwidth calculations and recalculated each Operating Company's production costs, using the assumption that Entergy Arkansas had acquired the ISES 2 capacity and continued to use it through 2006.

283. He used the computer programming "PROMOD" model to recalculate each Entergy operating company's fuel and purchase power costs for 2006, having been provided the model and data through discovery from Entergy. Then, Mr. Baron used this data to recalculate the 2006 Bandwidth formula, again assuming that Entergy Arkansas owned 164-180 MW of ISES 2 capacity in 2006.[174]

284. Based on the results of this recalculation, Mr. Baron opined that Entergy Arkansas' Bandwidth payments should increase by $23 million, with Louisiana being the primary beneficiary of this recalculation.

(1.) There Are Deficiencies In The LPSC's PROMOD Input Assumptions Which Prevent It From Accurately Capturing Market Conditions In 1996 And 1997

285. First, the LPSC's assumed purchase price for ISES 2 is flawed. Mr. Louiselle's testimony astutely points out some flawed assumptions by Mr. Hayet. Mr. Hayet calculated a proposed savings based upon estimates as to what Entergy

[174] 164 MW capacity is the generally accepted amount all parties agree would have been available to EAI.

Arkansas would have paid to acquire the ISES 2 capacity from Entergy pursuant to a right of first refusal that it held. Mr. Hayet's analysis assumed a purchase price equal to gross plant costs less Entergy's accumulated reserve for depreciation and less Entergy Arkansas' accumulated deferred income taxes.

286. As discussed by Mr. Schnitzer and Mr. Gallaher, the undersigned finds that Mr. Hayet's deduction of the accumulated reserve for deferred income taxes purposes results in an assumed purchase price lower than the price actually called for under the contract that provides the right of first refusal to Entergy Arkansas. Therefore, Mr. Hayet's analysis is flawed because it assumed a lower price than Entergy Arkansas would have actually paid, overstating the benefits of the transaction (Exhibit No. ESI-50 at 2-3).

287. Second, the LPSC's analysis of the benefits of the ISES 2 repurchase opportunity inappropriately speculates that Entergy Arkansas would have retained the ISES 2 from 1996 to at least 2006. Despite the APSC order that it had to provide consent prior to the ISES 2 capacity being used outside of Arkansas, there is little doubt that had Entergy acquired ISES 2, it would have used it to serve system-wide needs, and Entergy would have sought to obtain the necessary consent from the APSC. In all probability, substantial capacity would have been used outside of Arkansas.

288. The APSC's witness, Dr. Berry, supports this conclusion. Dr. Berry believes that Entergy Arkansas would have re-sold the ISES 2 capacity under Service Schedule MSS-4, to one or more of the Operating Companies since all of them were relatively deficient in base-load capacity (Exhibit No. AC-8 at 6).

289. In support of this position, Dr. Berry notes that Service Schedule MSS-4 requires all Operating Companies to have a proportionate share of Base-load Generating Units, like ISES 2 (Exhibit No. AC-8 at 6). In fact, Dr. Berry testified that the reason that some of the 256 MW of ISES 2 capacity became available to Entergy Arkansas in 1989 was because Entergy Mississippi made a Schedule Service MSS-4 purchase from Entergy Arkansas for five years in 1984.

290. Tables 1—3 in Dr. Berry's pre-filed testimony illustrate the disparities for base-load capacity among the Operating Companies. These tables represent relevant data for each Operating Company for the years ending 1988, 1995, and 1996. Dr. Berry chose to analyze those years because they represented the most recent calendar years prior to the date when Entergy Arkansas could have either not resold the returning ISES 2 capacity to EPI (1988), or repurchased the capacity from EPI in 1996 and 1997.

TABLE 1[175]

RATIO OF BASELOAD CAPACITY TO TOTAL CAPACITY

Year	EAI	EGS	ELL	EMI	ENO	System
1988	54%	NA	21%	27%	14%	34%
1995	61%	19%	21%	22%	14%	29%
1996	61%	19%	21%	22%	14%	30%

291. This table reflects the ratio of base load (nuclear and coal) capacity relative to total capacity for each Operating Company, where base load includes nuclear and coal capacity. Entergy Arkansas had a much greater amount of base load capacity than the other Operating Companies.

292. From this information and the information reflected in Tables 2 and 3 below, Dr. Berry opined that it was probable that if Entergy Arkansas had reacquired the ISES 2 capacity from EPI in either 1996 or 1997, then one or more of the other Operating Companies would have eventually become the ultimate owner of the ISES 2 capacity (through a Service Schedule MSS-4 purchase from Entergy Arkansas).

TABLE 2[176]

RATIO OF COAL CAPACITY TO TOTAL CAPACITY

Year	EAI	EGS	ELL	EMI	ENO	System
1988	20%	NA	0%	18%	0%	11%
1995	22%	9%	0%	12%	0%	10%
1996	22%	9%	0%	12%	0%	10%

293. Table 2 displays the ratio of coal-only capacity for each Operating Company. The table demonstrates that Entergy Arkansas owned a disproportionate share of coal capacity relative to the other Operating Companies.

[175] Exhibit No. AC-8 (referencing FERC Form 1's and Intra-System Bills).

[176] *Id.*

TABLE 3[177]

RATIO OF BASELOAD CAPACITY TO
AVERAGE DEMAND (ENERGY)

Year	EAI	EGS	ELL	EMI	ENO	System
1988	162%	NA	41%	96%	28%	85%
1995	131%	34%	34%	56%	26%	57%
1996	128%	32%	33%	59%	27%	55%

294. Table 3 shows the ratio of base load capacity to annual average energy use. Dr. Berry opines that one of the reasons for having base load capacity in a generation portfolio is to provide fuel savings. According to Dr. Berry, Table 3 reflects the fact that Entergy Arkansas had a relatively large amount of base load capacity available to provide fuel savings, while the other Operating Companies were light in this area.

295. Having demonstrated Entergy Arkansas's disproportionate share of base load capacity, Dr. Berry then demonstrated why and how Bandwidth payments and receipts are substantially impacted by which company owns the ISES 2 capacity.

296. According to Dr. Berry, the effect on Bandwidth payments and receipts is based upon the following factors: 1) One or more companies will necessarily be assigned the non-fuel costs for the 164 MW; 2) those same companies will receive a significant share of the fuel savings through the operation of the Service Schedule MSS-3; 3) the other operating companies will accordingly have fuel and purchased power impacts through the Service Schedule MSS-3; and, 4) the owning Operating Companies will have increased receipts, or reduced payments through the operation of Service Schedule MSS-1.

297. Next, Dr. Berry provides several examples of different ISES 2 ownership scenarios, demonstrating that the Bandwidth payments and receipts between the Operating Companies changes dramatically depending on which Operating Company owned ISES 2.

298. Ultimately, the undersigned finds little support for the LPSC central assumption that Entergy Arkansas would have initially received and/or retained the ISES 2 capacity through the present and into the future.

[177] *Id.*

299. The undersigned finds that the evidence, especially Dr. Berry's testimony, demonstrates that Service Schedule MSS-4 would have required Entergy Arkansas to sell the ISES 2 capacity to one, or a collection, of the Operating Companies. Given that Entergy Arkansas' receipt and retention of the ISES 2 capacity was a central, yet erroneous assumption in the LPSC's analysis, the undersigned assigns little weight to that analysis.

300. Third, the LPSC also speculates that Entergy needed increased capacity by the year 2000, which should be contrasted with Entergy historical projection that it did not need additional capacity until 2005. Mr. Hayet, based this assumption upon the report of a colleague, Mr. Falkenberg. Mr. Falkenberg's report was based upon a ten-state regional study and not a specific study of Entergy.

301. Moreover, the Falkenberg study used unreliable data containing "non-coincident peaks" as a measuring rod. These two deficiencies make it an unreliable source of information for an imprudence analysis of the ISES 2 buy-back decision.

302. However, even the Falkenberg study does not support a firm prediction that Entergy would have definitely needed additional capacity as early as 2000 (Exhibit AC-8, at 6). Ultimately, the LPSC's presumption of deficient capacity on the Entergy system in 2000 was an exaggeration and grossly overinflated the cost/benefit value of the ISES 2 repurchase offers. Consequently, the undersigned finds that this presumption was also not well-founded.

303. Fourth, the LPSC adjusted the settings in the PROMOD model to reflect the hypothetical sale of ISES 2 from EPI to EAI, but it then "failed to reduce the EPI sales transactions to reflect the fact that once EPI no longer owned the ISES 2 capacity, it would not continue to make energy sales from that capacity."[178] This error illogically leaves EPI with "up to 725 MW of sales obligations but only 645 MW of generation."[179]

304. The practical effect of this is that more expensive reliability generators are used to serve EPI while the Entergy system is served by units producing economy energy.[180]

[178] Entergy IB at 61.

[179] *Id*. at 62.

[180] *Id*.

305. EPI's customers were not captive and would not necessarily have accepted this more expensive energy, choosing instead to purchase energy from another utility.[181] Ultimately, once this error is corrected, the net benefits of repurchasing ISES 2 all but disappear.[182]

306. Fifth, the PROMOD model fails to satisfactorily account for the acquisition costs of the ISES 2 capacity. The LPSC admits that ISES 2 capacity would not have yielded a positive return for nine-fourteen years. Yet, the LPSC pays little to no attention to this important point. Therefore, the undersigned finds that this failure to account for acquisition costs is a fundamental flaw in the LPSC's analysis (Tr. at 1461 {Hayet}).

307. Sixth, the PROMOD analysis does not adequately capture the market's anxiety over the advent of cogeneration and retail open access. While Mr. Baron criticized the testimony of several key Entergy witnesses on this point, he acknowledges that the issue of retail open access was indeed real in 1996 and 1997. However, Mr. Baron opined that this perceived market condition should not have prevented Entergy from exercising its duty to continue to offer ratepayers the lowest possible cost of energy.

308. The undersigned recognizes this fact but finds it inapposite. The undersigned concludes that because of the market conditions at the time, Entergy could have been soundly criticized for purchasing the ISES 2 capacity.

309. Seventh, Mr. Hayet did no analysis comparing the cost of ISES 2 to the cost of Entergy returning other units to service (Tr. at 1525 {Hayet}). On the other hand, Mr. Hurtsell made just such a comparison, and when he compared the costs of acquiring ISES 2 to the costs of returning the most expensive unit to service, he discovered that it was still cheaper to bring back even the most expensive reserve unit (Exhibit No. ESI 97; Tr. at 2491-2494 {Hurtsell}).

310. A proper analysis of the prudence of Entergy's decision not to repurchase ISES 2 should have included a comparison with the costs of returning older units to service. Given that Mr. Hurtsell provided the only comparison in the record, the undersigned finds his testimony to be persuasive on the matter.

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[181] *Id*. at 62.

[182] *Id*. (noting that the correction of this error reduces the value of the ISES 2 repurchase by approximately $35 million).

311. Finally, the PROMOD model fails to gauge the probability that the APSC would have not permitted Entergy Arkansas to include the ISES 2 capacity in base rates. The APSC established that it was very unlikely that it would have allowed Entergy Arkansas to reacquire ISES 2 capacity in 1996.

312. Even Mr. Hyat acknowledged that contentious litigation with the LPSC over the approval of the original 1993 decision to divest the ISES 2 capacity from Entergy Arkansas to EPI concluded a mere six months before EAI received the offer to repurchase ISES 2 (Exhibit No. AC-24; Tr. at 1637-1638 {Hayet}).[183] While Mr. Hayet correctly asserts that the APSC could have reversed itself six months later, the undersigned finds that it is highly unlikely that it would have, given the timing of the offer and the fact that the APSC was trying to freeze rates (Exhibit No. AC-25; Tr. at 1642{Hayet}).

(2.) Other General Criticisms Of The PROMOD Model

313. The undersigned generally finds that the LPSC's PROMOD analysis was ill-suited to the task of reviewing the ISES 2 repurchase decision. Entergy established during cross-examination that Mr. Hayet's more theoretical modeling approach was not the best method to evaluate the "nitty-gritty" practical decisions that utility mangers must make on an almost daily basis (Tr. at 1468-70 {Hayet}).

314. In fact, the evidence establishes that Mr. Hayet had some trouble running the model to measure the impact the ISES 2 capacity, resulting in multiple re-runs due to errors. Mr. Hayet even had to request additional discovery from Entergy to help him understand the application of PROMOD to this project (Exhibit No. ESI 92; Tr. at 1569-1572 {Hayet}).

315. Furthermore, as indicated above, the LPSC's analysis of the benefits of the ISES 2 repurchase opportunity inappropriately speculates that Entergy Arkansas would have retained the ISES 2 from 1996 to at least 2006. Despite the APSC order that it had to provide consent prior to the ISES 2 capacity being used outside of Arkansas, there is little doubt that had Entergy acquired ISES 2, it would have used it to serve system-wide needs, and that this consent provision would not have prevented this. In all probability, substantial capacity would have been used outside of Arkansas.

316. The undersigned finds that the evidence simply does not meet the required

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[183] *See City of New Orleans v. FERC*, 67 F.3d 947 (D.C. Cir. 1995).

evidentiary threshold and does not establish serious doubts that Entergy acted imprudently. The undersigned further finds the expert testimony of LPSC's witnesses to be less probative than the experts called by Entergy. ISES 2 capacity would not have provided the savings the LPSC purports it would have (Tr. at 662, 674, 678, 690-692 {Hurtsell}).

ii. Entergy's Evidence Supports Its Decision Not To Repurchase ISES 2 Capacity

317. Even if assuming the LPSC had raised serious doubts of imprudence, Entergy's evidence rebuts the LPSC position. Entergy, through the testimony and studies of Mr. Hurtsell, Mr. Louiselle, and Mr. Schnitzer, establish that although not perfect, Entergy has reasonably operated its system so as to minimize production costs, and to maintain reliability, and correctly made the decision NOT to re-purchase the ISES 2 capacity. Entergy also called Mr. Frank Gallaher as a witness, and his testimony clearly rebuts the LPSC's claim. Mr. Gallaher provided confirmation of his previous pre-filed rebuttal testimony on June 18, 2008. Mr. Gallaher served in multiple key management positions for Entergy, including Senior Vice-President for Fossil Operations.

318. Mr. Gallaher had overall responsibility for the operation and maintenance of all fossil generating units, including ISES 2. He ultimately made the decision in both 1996 and 1997, not to obtain the ISES 2 capacity. Mr. Gallaher explained in detail the reasoning of his decision. Mr. Gallaher's testimony establishes that Entergy carefully evaluated the option to buy the ISES 2 capacity, but determined that the capacity was simply not needed, nor cost effective. At the time, Entergy had excess capacity, and the cost of acquiring the additional ISES capacity was not justified (Exhibit No. ESI-37 at 7-9).

319. Moreover, Mr. Gallaher explained the potential impact of two other factors in addition to the excess capacity factor; "industrial cogeneration" and "retail open access." Both of these potential developments had the potential to limit or decrease Entergy's customer load (Exhibit No. ESI-37 at 8; Tr. at 384-385, 609-613 {Gallaher}).

320. While the LPSC challenged Entergy's reliance on information contained in its 1995 IRP as being inadequate, the undersigned finds that Mr. Gallaher provided a reasonable and satisfactory explanation of how and why the IRP provided an adequate resource for him to make an informed decision. The undersigned finds Mr. Gallagher reasonably relied upon the IRP in making the decision not to obtain the additional capacity from ISES 2 (Exhibit No. ESI-37 at 13).

321. Mr. Gallaher was thoroughly familiar with ISES 2 and the energy market.

His decision not to obtain the additional ISES 2 capacity was certainly within the realm of reasonableness, considering the state of the energy market at the time. Mr. Gallaher candidly stated that from hindsight the purchase of the ISES capacity may have been something he wished he had obtained, especially when Entergy suffered a rolling blackout on July 23, 1999, which he describes as the "worst day of his professional career."

322. This rolling blackout, which lasted approximately three hours, is essentially the only one which occurred during Mr. Gallaher's twenty plus years watch and was certainly well within industry standards as recognized by both Entergy and the LPSC witnesses (no more than one day per ten years).

323. Mr. Gallaher's testimony, and the totality of the evidence in the record, supports a finding that the decision Entergy made at the time it decided not to obtain the ISES 2 capacity, was reasonable and based upon adequate information which was available at the time. It is also evident that acquisition of the ISES 2 capacity would not have prevented the rolling blackout in July 1999 (Tr. at 609-613 {Gallaher}).

324. Mr. Schnitzer provides testimony which further describes the Entergy process involved in both transmission and generation (Exhibit No. ESI-1). Overall, the evidence establishes that Entergy continually and significantly increased the amount of energy it purchased from third parties from 1999-2006, while decreasing dependence on its own oil and gas fired generation.

325. By 2006, the output from Entergy's own oil and gas-fired generation units had fallen by two-thirds, to 13% of the Entergy's system requirements. This energy was replaced by a combination of more cost effective purchases from merchant generators and other direct purchase. Mr. Schnitzer opined that overall Entergy saved its Operating Companies $900 million in production costs for 2006, with obvious savings to its customers and ratepayers (Exhibit No. ESI-1).

326. While the LPSC severely criticized Entergy's reliance on the IRP since it only covered a ten-year projection period, noting that Mr. Schnitzer's consulting studies generally always cover a twenty-thirty year projection period, the undersigned is convinced that Mr. Gallaher had sufficient information to make an informed decision.

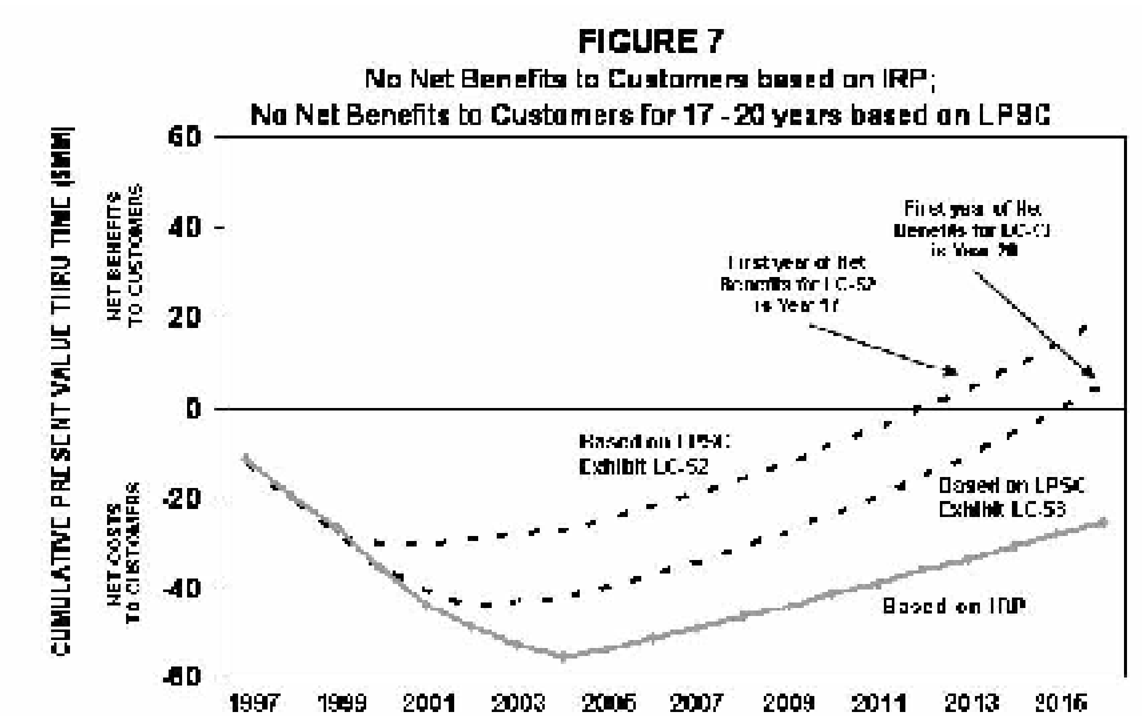
327. Mr. Schnitzer corroborates Mr. Gallaher's testimony in sufficient detail. He studied market conditions and the ISES 2 capacity and extrapolated this information another ten years, to establish that even from hindsight, acquisition of ISES 2 was not cost effective. He further testified at the hearing that in his opinion, he believed Mr. Gallaher had enough information available in the IRP

document to readily assess whether he should obtain the ISES 2 capacity.

328. Mr. Schnitzer testified that there were many other entities which declined to obtain the ISES 2 capacity, which indicates to him that the market had an excess capacity at the time, and that the ISES 2 capacity was not necessarily a perceived bargain (Tr. at 1049-1051 {Schnitzer}).

329. In his opinion, Entergy would have been in a multi-million dollar hole before it would have seen any return on the ISES 2 investment, leading him to the conclusion that Mr. Gallaher made the correct decision.

330. In his Figure 7 below, Mr. Schnitzer summarizes the cumulative present value of the cost of the ISES 2 decision over a 20 year period under both the LPSC's and Entergy's view of the wholesale market price compared to the corrected ISES 2 costs. When a curve is below the "X" axis that means that ISES 2 costs exceed customer benefits on a cumulative basis up to that point. When a curve goes above the "X" axis, then customer benefits exceed costs on a cumulative basis.



331. Mr. Schnitzer explains:

> Now, in my rebuttal testimony I went and said now suppose we did that, just based in what was in the IRP, and I conclude that that's right. And that is shown graphically. Your Honor, on figure 7 of my rebuttal testimony on page 21 where Mr. Gallaher had, you know, up through 2005, you know—and it's the bottom line on that curve. And so he had all the numbers, that when I calculate them, the decision would have been almost $60 million in the hole, you know, as of the last year of his IRP data.

(Exhibit No. ESI-41; Tr. at 1051 {Schnitzer}).

332. Thus, Mr. Schnitzer's testimony demonstrates that 1) the IRP was a reliable projection of market condition in 1996 and 1997; 2) the IRP clearly demonstrated that the acquisition of ISES 2 was not cost-effective; and 3) that even the LPSC's ISES 2 projections, once corrected, reveal that ISES 2 would not have been profitable for approximately seventeen to twenty-years after its acquisition. The undersigned finds Mr. Schnitzer's testimony to be probative and convincing.

(1.) Additional Evidence Establishes That Market Conditions In 1996 and 1997 Cautioned Strongly Against Acquisition Of ISES 2 Capacity

333. Moreover, other evidence in this proceeding demonstrates that there was a surplus of capacity on the market in 1996 and 1997 and that there was a valid belief that this surplus would continue to grow. During his rebuttal to the oral surrebuttal testimony, Mr. Schnitzer provided additional testimony pertaining to market conditions, citing an independent objective study done by Moody's Investor Services from August 1995, which described the prevailing market conditions as being one with excessive surplus capacity (Exhibit No. ESI-76; Tr. at 2662-2664; 2668 {Schnitzer}). Mr. Schnizter's analysis of market conditions corroborates this prevailing view of surplus capacity.

334. Additionally, Mr. Louiselle provided testimony demonstrating that even the LPSC recognized surplus market conditions existed in 1996 and 1997 (Tr. at 2722-2723 {Louiselle}). To that end, Mr. Louiselle referenced several excerpts of prior testimony from the LPSC's staff members, in which they acknowledged the excessive surplus market conditions existing in and around 1996. The undersigned finds that this evidence significantly corroborates Entergy's description of the energy market at the time it was offered the right to repurchase the ISES 2 capacity (Exhibit Nos. ESI-60; ESI-111).

335. Moreover, FERC staff witness John Sammon provided crucial corroborating testimony on this issue as well. Mr. Sammon opined that Entergy was not imprudent. Mr. Sammon testified that at the time, Entergy had excess capacity, natural gas prices were low, and there was a favorable short-term purchase power market.

336. He further testified that Entergy's system planners were concerned about loss of Entergy's large industrial load to cogeneration, and therefore had multiple reasons not to buy additional long term capacity.

337. Mr. Sammon rejected the use of a computer model to address an issue such as imprudence, as being essentially unreliable and beyond established directives from the Commission (Exhibit No. S-18).

338. Mr. Sammon also set forth an excellent history into the background of the Entergy System and how Entergy Arkansas had a right of first refusal to buy 164 MW from EPI, which is very useful when examining Entergy's decision (Exhibit No. S-1, S-18). Mr. Sammon testified that in the 1970s, Entergy system was almost entirely based upon oil and gas fired generation.

339. Due to high gas and oil prices and federal laws curtaining construction of gas fired units, Entergy expanded into nuclear and coal-fired generating units. ISES 1 and 2 are two coal-burning units located on the Entergy Arkansas system. Entergy Arkansas and Entergy Mississippi owned shares of ISES 2.

340. While Mr. Sammon sees some flaws in the Entergy decision making process and agreed with LPSC 's witness, Mr. Hayet to some extent in this regard, he opines that Entergy was not imprudent at any time relevant to these proceedings (Exhibit Nos. S-1, S-18).

341. Mr. Sammon notes that there was nothing particularly special about the ISES 2 opportunity, especially during the mid-1990s, when gas prices were low. (Exhibit No. S-18 at 22). Of further significance is Mr. Sammon's testimony that he believes that the energy market in general did not value this coal-fired generating capacity very highly at the time (Exhibit No. S-18 at 24).

342. In support of this opinion he cites the fact that EPI eventually sold the capacity at roughly the net depreciated book cost that it had first offered to Entergy Arkansas for.

> The per kW off-system sale price for the ISES 2 capacity was less than the per kW installed cost of a new combined-cycle gas-fired unit in spite of the fact that the remaining service life of ISES 2 was

> approximately that of a new combined-cycle unit, i.e. 30 years. This suggests that the market did not value this coal-fired capacity very highly at the time. It may not have appeared to a prudently managed utility that this ISES 2 capacity offer was all that great an opportunity. The market seems to suggest this was the case.

(Exhibit No. S-18 at 22).

343. Mr. Sammon opines that from hindsight and his own investigation and historical knowledge of the period, that there was no way for Entergy to accurately predict what future fuel prices would be, what load growth would be, or what other costs would be, in the future. As previously indicated, the official FERC Staff position is that Entergy was not imprudent in this case, and the undersigned puts great weight on this position, for this issue.

344. The undersigned finds that Mr. Schnizter, Mr. Louiselle and Mr. Sammon accurately described market conditions at the time Entergy decided not to obtain the ISES 2. There appears to be little dispute that the energy market in 1996 and 1997 was experiencing a glut of capacity that was projected to grow into the future.

345. Given these conditions, reasonable system planners focused on increasing flexibility through a variety of methods, including short-term power purchases from third-parties. More importantly, they were avoiding investments in long-term fixed baseload capacity, like ISES 2. Therefore, the undersigned finds that market conditions in 1996 and 1997 militated against the repurchase of ISES 2.

(2.) Entergy Also Faced Advent Of Cogeneration And Retail Open Access During This Very Time Period

346. It was reasonable for Entergy to perceive a real threat from cogeneration and Retail Open Access, and that these factors would contribute to a loss of load. Cogeneration refers to the simultaneous generation of both electricity and useful heat from industrial customers, where industrial customers in turn supply their own energy to themselves. Mr. Gallaher's rebuttal testimony demonstrates that the threat of Entergy losing load to cogeneration was quite real in and around 1996 (Exhibit No. ESI-37 at 8) (noting that "[l]ow gas prices and rapid improvement in combined cycle turbine technology had made cogeneration a viable alternative of many of Entergy's industrial customers[,]" and that "in 1996 Entergy was aware that it soon would lose 500 MW of its industrial customer load to two

cogeneration projects that were then under construction.”)[184]

347. Retail Open Access (ROA) refers to a move by state regulators in the mid to late-nineties to explore deregulation of retail rates, which would have allowed retail customers “to shop” and choose among competing power suppliers.”[185]

348. By April of 1996, the advent of ROA was, according to Entergy and many energy experts, “more a question ‘when’ rather than ‘if.’”[186] Increased competition in the retail sector reasonably led Entergy to be concerned that its industrial load customers would find it more economic to purchase energy from another source.[187]

349. Consequently, Entergy was also concerned that if it lost significant load, then it would not be able to recover the cost of the capacity that it already had, a condition commonly referred to as “stranded costs.”[188] Ultimately, the debacle of California’s deregulated retail energy market, led most states to abandon any thought of ROA.

350. However, in 1996 and 1997 Entergy could not have possibly foreseen the death of ROA and had every reason to believe that it would soon be a reality in many of the states that it served. Consequently, the undersigned finds that both

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[184] FERC Staff witness, Mr. Sammon, also recognized that Entergy’s system planners were concerned about losing large industrial load to cogeneration, and therefore had multiple reasonable reasons to not buy additional long-term capacity (Exhibit No. S-18).

[185] Entergy IB at 77.

[186] *Id*. (noting that the 1997 Falkenberg testimony, which Mr. Hayet relied upon to support his claim that Entergy would need additional capacity in 2000, recognized that retail open access was basically an inevitability).

[187] *Id*. at 78.

[188] Stranded costs may arise under retail competition, where non-regulation may make prices dependent upon the wholesale market instead of costs actual incurred. If a utility has generation costs that are higher than the wholesale market, stranded costs may result, costs which cannot be recovered, unless relief is provided from the applicable utility regulatory entities through rate increases. Mr. Gallaher testified such relief was very uncertain for any stranded costs Entergy may have incurred during the time period in question (Tr. at 2470-71{Gallaher }).

cogeneration and ROA were viable threats to Entergy's customer load and that the introduction of additional capacity, like ISES 2, would have only exacerbated this threat (Exhibit No. ESI-37 at 8; Tr. at 384-385, 609-613 {Gallaher}).

351. Furthermore, during the period 1996 through 2006, Entergy took steps to reduce its dependence on "owned generation" in an effort to increase market flexibility, demonstrating that Entergy, like many utilities at the time, was concerned about excess capacity. This energy was replaced by a combination of more cost effective purchases from merchant generators and other direct purchases.

(3.) The Market Reaction To EPI's Attempted Sales Of The ISES 2 Capacity Also Demonstrates The ISES 2 Capacity Was Unattractive In 1996 And 1997

352. In addition to the fact that the energy market in 1996 and 1997 strongly warned against the repurchase of ISES 2, EPI's difficulties in selling the ISES 2 capacity strongly indicate that it was not the steal that the LPSC claims it was. Mr. Schnitzer's evaluation, which supported Mr. Gallaher's decision to pass on the ISES 2 repurchase opportunity, noted that many other entities that declined to obtain the ISES 2 capacity (Tr. at 1049-1051 {Schnitzer}).

353. Mr. Schnitzer interpretes this market hesitance as an indication 1) that the market had an excess capacity at the time and 2) that the ISES 2 capacity was not necessarily a perceived bargain. With respect to the latter interpretation, Mr. Schnitzer's testimony emphasized the fact that ISES 2 could have been obtained by nine or ten other potential purchasers, who also declined, indicating the price was too high and/or that capacity was at a surplus (Tr. at 2688-89 {Schnitzer}).

4. Summary

354. In summary, the undersigned finds that the LPSC has failed to raise the "serious doubts" required for a consideration of imprudence. However, the undersigned went further and considered the issue of imprudence and finds that the evidence establishes that Entergy's planning process, as presented by Mr. Gallaher, Mr. Hurtsell, Mr. Louiselle, and Mr. Schnitzer, supports Entergy's decision not to acquire the ISES 2 capacity at the time was reasonable and prudent.

355. In reaching this finding, the undersigned considered the availability of low cost wholesale capacity available for purchase at the time; the availability of additional "mothballed" generating units which could be brought back on line; and the potential implications of cogeneration and ROA, both of which brought a

perceived likelihood of a reduction of load; the cost of ISES 2; and the recent completion of extended litigation which delayed the final divesture of ISES 2 from Entergy Arkansas to EPI.

356. Since the undersigned finds that Entergy was not imprudent, the issue of what is an appropriate remedy is moot. However, the undersigned believes that in the event the Commission was to make a contrary finding, the appropriate remedy would be the remedy, in part, advocated by the APSC through the testimony of David Helsby, which would assess any costs of imprudence to Entergy's shareholders and not to the Arkansas ratepayers.

357. Mr. Helsby additionally seems to advocate that Entergy Arkansas customers should receive additional compensation in the sum of approximately $ 7 million which reflects the difference in Entergy Arkansas' re-computed declining production costs and should be added to Mr. Helsby's imprudence assessment of $ 21.74 million (Exhibit No. AC-19 at 11-20).

358. Entergy's witness Bruce Louiselle vehemently disagrees with the additional assessment and contends that any "additional compensation" would have to be ordered by the APSC, not by the Commission (Exhibit No. ESI-50 at 57).

359. Ultimately, the undersigned finds that if any imprudence assessment is made, it should be limited to the Bandwidth adjustments, which should be borne by Entergy.

360. In conclusion, the undersigned finds that Entergy was not imprudent and that no remedy is justified. The undersigned finds that Mr. Gallaher's testimony, and the totality of the evidence in the record supports the premise that the decision Entergy made at the time it decided not to obtain the ISES 2 capacity, was reasonable and based upon adequate information.

C. Ameren Contract Issue

361. **ISSUE:** What is Entergy Arkansas' ability to recover Bandwidth payments from Ameren UE under the 1999 Service Agreement between EAI and Ameren UE? If EAI may not recover Bandwidth payments from Ameren UE under the 1999 Service Agreement, what is the obligation to pass through Bandwidth credits to ETEC under the 2004 Service Agreement between EGSI and ETEC?

362. The undersigned finds that Entergy did properly allocate a pro rata share of the Bandwidth payment to Ameren, pursuant to its contract with Ameren, and pursuant to the Bandwidth calculations and Service Schedule MSS-3.

1. Background

363. Entergy Arkansas and Ameren entered into a service agreement effective April 1, 1999, prior to the implementation of the Bandwidth remedy. Ameren is a corporation organized and existing under the laws of the State of Missouri and is a loading serving entity (Exhibit No. AMN-8). The contract provides for the sale of 165 MW of capacity from Entergy Arkansas' White Bluff coal plant.

364. If White Bluff is not available, Entergy will substitute another plant. There is a fixed $11.25 per kW monthly rate for capacity and a variable energy rate based upon a formula, which is contained in Appendix A of the contract, and which is based upon the fuel and purchased power energy rate (FPER) (Exhibit Nos. S-5, AMN-2 at 3).

365. The FPER is a formula that calculates Ameren's monthly energy in dollars and usage based upon certain variable expenses of the billing cycle. These variable expenses are fuel and purchased energy (Exhibit No. S-1 at 28). Through the variable "PE" (purchased energy expense-Account 555), Entergy allocated a share of Entergy Arkansas' 2006 Bandwidth payments through to Ameren.

366. The Ameren agreement, Appendix A, sets forth a formula which is intended to capture all of Entergy Arkansas' energy costs associated with the transactions. Those energy costs fall into two categories in the formula rate: Variable FE (fuel expense reflects all energy costs incurred at Entergy Arkansas' owned generation; and Variable PE (purchased energy expense reflects all other energy expense resulting from transactions with other companies). The part of the formula that is at issue here is the variable PE, which is charged to Account 555 (Purchase Power).

367. Ameren does not dispute that a portion of Entergy Arkansas' Bandwidth payments result from serving Ameren's load. Moreover, Ameren does not contest Entergy's calculations in determining its proposed allocated payment. Ameren argues the service agreement does not provide for it to be assessed a portion of Entergy Arkansas' Bandwidth payment.

368. Entergy invites a two prong analysis in order to clearly understand the contractual issue and how the adoption by the Commission of the Bandwidth remedy impacts wholesale requirements customers such as Ameren. First, Entergy suggests that the initial analysis here must determine whether the Bandwidth payments are considered to be "Purchased Power" expenses, which corresponds to Account 555.

369. If so, then a determination must be made as to whether the Bandwidth

payments are for purchased energy or if they are considered to be a purchased capacity expense. Entergy asserts that purchased power may include both purchases of energy and capacity, but that the variable PE here, only allows for recovery of purchased energy.

2. Legal Standard For Interpreting The Contract

370. In interpreting a contract, the Commission looks first to the plain language of the contract itself.[189] Wherever possible the contract should be construed as a whole.[190] Moreover, it is a cardinal rule in contract construction that contracts should be read to give effect to all its provisions and to render them consistent with each other.[191]

371. Furthermore, when interpreting a contract, the court must give effect to the unambiguous intent of the parties.[192] In the absence of ambiguity, the intent of the parties must be ascertained from the language within the four corners of the document, without resort to parol or extrinsic circumstances. Furthermore, a contract is not ambiguous simply because the parties disagree with its interpretation.[193]

372. Moreover, in wholesale electricity markets it is presumed that, the rate charging party and the party charged are sophisticated businesses enjoying presumptively equal bargaining power, who are generally expected to negotiate a just and reasonable rate between them.[194]

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[189] *New York Independent System Operator, Inc., v. Astoria Energy LLC.*, 118 FERC ¶ 61, 216 (2007).

[190] *Southwest Power Pool, Inc.*, 109 FERC ¶ 61,010 (2004).

[191] *Mastrobuono v. Shearson Lehman Hutton, Inc.*, 514 U.S. 52, 63 (1995).

[192] *Southern California Edison Co. v. FERC*, 502 F.3d 176 (D.C. Cir. 2007).

[193] *Papago Tribal Utility Authority v. FERC*, 723 F.2d 950 (D.C. Cir. 1983).

[194] *Morgan Stanley Capital Group, Inc. v. Public Utility District No. 1 of Snohomish County*, 128 S.Ct. 2733 (2008).

3. The Evidence Supports Entergy's Position That The Contract Allows For Entergy Arkansas To Allocate To Ameren A Pro Rata Share Of The Bandwidth Payment

373. Entergy asserts that since the Commission has determined that the Bandwidth payments should be recorded in Account 555, it has implicitly determined already that the Bandwidth payments are purchased power expenses.[195] Additionally, Entergy asserts that the FERC only has jurisdiction over sales of wholesale power in interstate commerce and transmission of power in interstate commerce.

374. The Bandwidth payments are designed to equalize production costs and necessarily must therefore constitute payments for wholesale sales among the Operating Companies. Entergy argues that clearly the Bandwidth payments are not related to "transmission."

375. Therefore, for the FERC to have had jurisdiction in this matter from the very beginning, it has established that the Bandwidth payments are for the sale of electric power in interstate commerce, and therefore are for the sale and purchase of "energy."[196]

376. From this point, Entergy logically goes on to argue that only those purchased energy expenses, as opposed to purchased capacity expenses, are recoverable under the Ameren contract, which is what it has billed Ameren for.

377. Through the testimony of consultant Michael Schnitzer, Entergy provided an in depth analysis of the service agreement. Mr. Schnitzer opines that since the Commission authorized Entergy to record Bandwidth payments in Account 555, this confirms Entergy's view that the Commission recognizes that the Bandwidth payments represents wholesale sales of energy.

378. Moreover, he views it as significant that the Commission approved Entergy's proposal to place the rough production cost equalization remedy in Service Schedule MSS-3, which the Commission noted has historically been used to allocate energy costs among Operating Companies.

379. In his opinion, since the RPCE payment is exclusively fuel and purchased energy costs, it should logically be included in Ameren's contracted fuel and purchased energy rate (Exhibit No. ESI-41 at 33; Tr. at 1012-13 {Schnitzer}).

[195] Entergy IB at 92.

[196] *Id.* at 95.

> I think, as I've stated in my testimony, that it's clear to me that the RPCE payment falls within purchased energy expense charged to Account 555, and therefore, the Ameren UE energy ratio share, if you will, of that RPCE payment is properly included in Ameren's bills.

(Tr. at 1013{Schnitzer}).

380. Entergy presented extensive evidence which addresses the plain language of the contract, historical dealings between the parties, and the intent of the parties, through the testimony of Mr. Hurtsell and Mr. Bunting. Mr. Shawn Schukar, provided evidence for Ameren. Neither party called an independent contract law expert to review the contract or to testify about the express language in the applicable provisions of the agreement.

381. While Mr. Schukar did an excellent job explaining Ameren's position, the undersigned finds the testimony of Mr. Bunting (Tr. at 742-745 {Bunting}) and Mr. Hurtsell (Tr. at 627-733 {Hurtsell}), to be most probative on this issue.

382. Mr. Schukar attempts to distinguish the descriptive phrase "purchased energy expense," and argues this creates a sub-category of costs related to specific purchases recorded in Account 555, accountable only by a MWh basis (Exhibit No. AMN-1 at 12). He argues this sub-category was not intended to include RPCE payments.

383. He further argues that the RPCE payments are merely recorded in Account 555 because that account also includes "net settlements" for the exchange of energy and capacity reserves and for transactions under pooling agreements. He therefore argues that "purchased energy expense and net settlements are distinct categories of costs which are included in Account 555.

384. He opines that only those costs falling under the purchased energy expense sub-category is eligible for pass through to Ameren. Mr. Schukar admits in his deposition testimony, however, that he believes the Commission has found that RPCE payments represent net settlements for exchange of energy and capacity and that there were no capacity charges contained within the 2007 RPCE payments. (Exhibit No. ESI-49). In other words he admits that Entergy billed Ameren for only energy related expenses.

385. Entergy's billings to Ameren reflect the proper formula was used by Entergy and establish that the determination of "Variable PE" includes all costs recorded to Account 555, with the billing calculation subsequently excluding capacity related costs (Exhibit No. AMN-7).

386. Mr. Bunting opines that Account 555 covers any cost related to a purchased power expense, to include capacity related as well as energy related costs (Exhibit No. ESI-44 at 22). He describes how Entergy charged costs to Ameren, by using the variable PE which begins with all of Entergy Arkansas' purchased power costs charged to Account 555. Entergy then excluded all purchase capacity costs from Account 555. The remaining purchased energy expenses were billed to Ameren (Exhibit No. ESI-44 at 24-27).

387. Mr. Hurstell opines that the 1999 agreement was intended to allow Entergy Arkansas to recover all energy costs allocable to Ameren as he was involved with implementation of the contract from its inception (Exhibit No. ESI-20; Tr. at 630, 638-39 {Hurtsell}). To not allow recovery of the pro rata portion of the Bandwidth payments related to energy expenses, in his opinion, would be inconsistent with the plain provisions in the contract.

388. Of additional significance is his testimony describing the provisions of an earlier contract between Entergy and Ameren in 1991, which contained a significantly higher fixed payment by Ameren ($52.00 per kw hour) associated with recouping energy related expenses.

389. Mr. Hurtsell described how Ameren expressly declined to continue this type of arrangement and instead signed on to the variable energy billing provision contained in the present contract, because it did not want to pay a high fixed cost for purchased energy expenses. Although the information provided by Mr. Hurtsell is based upon a hearsay source; his conversations with Mr. Henry Thompson, an Entergy employee who was actively negotiating the contract with Ameren, the undersigned finds the evidence to be reliable.

390. Mr. Hurtsell was actively involved in the contract process and regularly discussed the negotiations with Mr. Thompson who had an office right next to his. His knowledge was first hand and the information remains un-rebutted (Tr. at 647 {Hurtsell}).

391. Mr. Hurtsell explained that there are only two types of expenses passed through the contract; fuel related and purchased energy: i.e. energy generated by Entergy units or provided pursuant to other means through the energy market (Tr. at 647-49 {Hurtsell}).

392. Moreover, APSC witness Dr. Berry gave limited but valuable testimony on this issue in support of Entergy, but argued that if the Commission decided for Ameren on this issue, that in his opinion, the difference should not be made up by Entergy Arkansas' rate-payers. He supports Entergy's position to the extent that his analysis concludes that the Entergy Arkansas Bandwidth payment is

characterized primarily as fuel and purchase power related.

393. Finally, FERC staff witness John Sammon gave some valuable evidence on this issue (Exhibit No. S-1). Staff sides with Ameren, primarily taking the position that the Ameren contract does not expressly allow for pass through of an allocation of the Bandwidth payments to Ameren. Mr. Sammon gave testimony to this effect. However, he also testified that Ameren should pay a share of the Bandwidth payment as a wholesale requirements customer.

394. The undersigned expressly rejects the portion of Mr. Sammon's opinion which purports to interpret the contract. While Mr. Sammon is a licensed attorney and has experience with the type of contract used within the industry as a regulatory analyst with FERC, no foundation was established by any party to qualify Mr. Sammon as a contract law expert.

395. The fact that he is an attorney does not qualify him per se as a contract law expert, and he did not appear as an attorney in these proceedings. Moreover, no foundation was presented to otherwise establish Mr. Sammon has sufficient experience to qualify as an expert in contract law. He has not written nor lectured on the subject.

396. Nor was it established that Mr. Sammon was ever accepted as a contract law expert in any state or federal judicial proceeding. While the undersigned gives his opinion some weight because of his experience in the regulatory field, his opinion cannot be accepted as dispositive on this particular legal issue. Moreover, since he was not a negotiating party, Mr. Hurtsell's testimony is given considerably more weight as he satisfactorily describes the intent of the parties on this issue. Mr. Sammon's opinion is therefore credited only with that expertise normally associated with his current duties and regulatory experience. In this regard, his regulatory experience does qualify him and does support his opinion that he believes Ameren is responsible for paying a portion of the Bandwidth payments associated with Ameren's purchased energy related expenses.

397. Mr. Sammon stated that it was certainly reasonable for Entergy to allocate a pro rata share of its Bandwidth payments to wholesale customers based solely on firm energy (Exhibit No. S-1 at 34). Mr. Sammon believes that Ameren should pay its fair share of Bandwidth payments and that the payments should be treated as cost equalization payments pursuant to Service Schedule MSS-3, as an exchange of energy; the sale of cheaper energy in return for more expensive energy.

398. While Mr. Sammon prefers to characterize the assessment to Ameren as production costs equalization payments, instead of payments related to the

purchase of energy, Mr. Sammon clearly believes that it is appropriate for Ameren to be allocated its share of the Bandwidth payment. Mr. Sammon testified as follows:

> When the Ameren contract was entered into, neither party (Ameren or Entergy Arkansa) could have contemplated that Entergy Arkansas would have to make production cost equalization payments to other Operating Companies during the term of the contract. Appendix A. FPER, is intended to measure Entergy Arkansas' actual monthly variable cost of producing energy. If FPER is strictly and literally construed, it will not reasonably measure Entergy Arkansas' monthly fuel and purchased energy costs because the production equalization payments Entergy Arkansas is now making cause it to share its cheap fuel costs with the other Operating Companies.

(Exhibit No. S-1 at 36).

399. In essence, little weight is given to the FERC Staff position on this issue because it relies upon the testimony of Mr. Sammon on a purely legal contract law interpretation matter. Moreover, his opinion is contradictory as it also firmly establishes that he believes Ameren should pay a share of the Bandwidth payments, which implicitly supports Entergy's position.

400. The undersigned finds it unnecessary to adopt Mr. Sammon's alternative theory for payment. The undersigned finds that the express terms and the plain language of the 1999 service agreement does allow for pass through of "purchased energy expenses," as part of the formula rate for fuel and purchased energy (Exhibit No. AMN-1 at 9), and that it was therefore proper for Entergy to allocate a portion of the Bandwidth payment to Ameren based upon this contract, which was based upon energy related expenses. The fuel and purchased energy rate includes costs determined by "variable PE", and is charged to Account 555 (Purchased Power), which is what Entergy has been directed to do by the Commission.

401 Entergy's arguments are persuasive, especially in light of the fact that Ameren did not call its own contract law expert. Mr. Schukar's testimony did not sufficiently rebut Entergy's extensive evidence. The Bandwidth payments constitute a portion of the price Entergy Arkansas pays for its share of the total System's energy allocated to it under Service Schedule MSS-3 of the System Agreement.

402. Since the Bandwidth payments represent a reallocation of payments made

under the System Agreement, they constitute a portion of the payments Entergy Arkansas makes for energy allocated to it under the Service Schedule MSS-3.

403. The Bandwidth remedy, approved to achieve rough cost equalization of production costs, contemplates wholesale requirements customers will have the responsibility for their allocated share of any payments or receipts.

404. The undersigned has a tough time imagining how the Bandwidth formula would work if wholesale requirements customers were permitted to avoid the effects of the remedy. The undersigned agrees with Entergy that this would frustrate the purpose of the Bandwidth remedy.[197]

405. Under the Bandwidth remedy, cost allocation and rate setting are not separate and distinct because the costs incurred on behalf of Entergy's customers, like Ameren here, is used to determine the amount of the remedy payment.

406. The undersigned also agrees with Entergy that Ameren would essentially be granted a windfall. It would avoid its fair share of purchased energy related expenses. This would result in an absurd interpretation of the contract. While the Bandwidth remedy was not in effect when the 1999 Ameren agreement was entered into, the agreement does obligate Ameren to pay its share of Entergy's energy related expenses attributable to Ameren.

407. According to Entergy, Ameren has simply contorted its reading of the contract to ignore the fact that the historic allocation of the Entergy System's energy expenses to Entergy Arkansas under Service Schedule MSS-3, have been purchased energy expenses, recoverable under the contract, but now absurdly takes the position that when those same costs are reallocated among the Operating Companies pursuant to the Bandwidth formula set forth in the same Service Schedule MSS-3 rate schedule, the costs "somehow cease to be purchase energy expenses."[198]

408. Entergy further argues that Ameren's characterization of the final reallocation of costs implemented through the Bandwidth payments as an "administratively-determined payment" shows the fallacy of Ameren's argument, and establishes Ameren is merely attempting to secure a windfall.[199] The undersigned sees the merit of Entergy's position.

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[197] Entergy RB at 58.

[198] *Id*. at 53.

[199] *Id.*

409. To interpret the contact as advocated by Ameren will create a windfall for Ameren. The plain language of the contract and the only reasonable interpretation of the contract, clearly establishes that Entergy has properly allocated a pro rata portion of the Bandwidth payment attributable to Ameren's energy usage.

410. The undersigned does not find the contract ambiguous, but assuming arguendo for purposes of this discussion that is in order to have an opportunity to examine relevant parol and extrinsic evidence, the undersigned finds the testimony of Mr. Hurtsell clearly establishes that Ameren had agreed to pay a variable purchase energy expense, in lieu of a higher fixed energy charge.

411. Mr. Hurtsell's testimony is un-rebutted that when the parties were negotiating the present contract, Ameren intentionally declined to pay a fixed energy charge as it had done in the earlier 1991 contract and signed up for a variable purchase energy expense provision. That charge is now paid through the Bandwidth remedy pursuant to the Commission's Opinions 480 and 480-A. Therefore, the past conduct of the parties supports Entergy's position

412. With the creation of the Bandwidth formula, this allocation is passed through to Ameren pursuant to this method, and is not deemed to be unjust, unreasonable, discriminatory or preferential. While the Bandwidth may or may not have been contemplated, costs related to purchase energy expenses, clearly were, and these costs may now be recovered pursuant to the Bandwidth formula, through Service Schedule MSS-3.

4. The Ameren Contract Has No Impact Upon ETEC

413. Furthermore, the undersigned finds the Ameren agreement with Entergy has no precedential value to the distinct contract of ETEC, which must be defined by its own terms, and the intent of the parties. The undersigned finds the testimony of ETEC witness, Mr. Robert Smith, to be highly probative on this issue. Mr. Smith testified that the ETEC contract with Entergy contains different provisions, and in his opinion should not have any precedential value over the ETEC contract.

414. Both Entergy and ETEC agree that ETEC should continue to be allocated a share of Bandwidth receipts under the agreement. In Mr. Smith's opinion the ETEC agreement with Entergy expressly allows for and identifies energy charges allocated to Entergy Gulf States under the Entergy Systems Agreement, including the Service Schedule MSS-3, as being included in the monthly fuel and purchased power adjustment clause (Exhibit Nos. ETEC-1 at 1-2, ETEC-2). The opinions of Mr. Smith are un-rebutted in the record and are therefore deemed dispositive on

this issue.

D. Nuclear Depreciation Issue

415. **ISSUE:** What is the appropriate nuclear depreciation and decommissioning expense that should be used for the 2006 Bandwidth calculation?

416. The undersigned finds that Entergy did erroneously calculate the nuclear depreciation and decommissioning expenses. The undersigned finds the appropriate nuclear depreciation expenses should be based upon the actual duration of the license in effect, as granted by the NRC, to include any granted extensions.

1. Background

417. Entergy maintains it has correctly used the nuclear depreciation and accompanying decommissioning expenses set by the applicable Retail Regulators in determining the Bandwidth calculation, as set forth on the FERC Form 1.

418. This is a significant issue for several parties. The MPSC asserts the correct depreciation expense should reflect the life of the NRC approved license, and pro-offers that a contrary finding could cost the Mississippi ratepayers some $7.5 million in Bandwidth payments (Tr. at 1972). Likewise, the APSC asserts the issue could involve some $28 million for the Arkansas ratepayers, if Entergy Arkansas has to increase its payments under the Bandwidth calculation to the other Operating Companies (Tr. at 347).

419. To summarize, there are five nuclear units within the Entergy System. Entergy Arkansas' nuclear generating units ANO 1 and ANO 2 units were granted 20 year license extensions by the NRC, in 2001 and 2005, respectively, for a new life use expectancy of 60 years. These units are regulated by the APSC. The APSC, however, has left the depreciation rate the same, reflecting a 40 year life, which is what Entergy used in the Bandwidth formula.

420. The APSC has reflected the 20 year license extension in its retail rates for decommissioning, but not for depreciation. It has reset the decommissioning rate to zero for both units, using the 60 year life. It is undisputed that the APSC had originally set the 40 year depreciation rate for ANO 1 and ANO 2 upon the duration of the original 40 year license granted by the NRC.

421. ANO 1 and ANO 2 have received license extensions now dating through 2034 and 2038, respectively. Entergy's reduction of the decommissioning

expense relating to units ANO 1 and ANO 2, to zero dollars, is based upon the belief that due to the granted 20 year license extension, it will have sufficient earnings in the decommissioning fund balance necessary to decommission the units. The last Entergy projected earnings study, however, is over six years old (Exhibit Nos. S-8 at 14, S-11).

422. Of the remaining three nuclear units, Waterford 3, River Bend, and Grand Gulf, none have applied for nor received a license extension. Entergy Louisiana owns the Waterford 3, and is regulated by LPSC. Entergy Gulf States owned River Bend at all relevant times herein, and was regulated by LPSC and PUCT, with approximately half the load divided between Louisiana and Texas (Exhibit No. S-18). PUCT has kept the depreciation and decommissioning rates for River Bend at forty years.

423. For Waterford 3 and River Bend, the LPSC, however, has reflected an expected license extension of sixty years for both decommissioning and depreciation, based upon an expectation that the NRC will grant at some future time, a license extension. The original license expiration date is December 2024 and August 2025, respectively.

424. Grand Gulf is a single nuclear unit, which 90% is owned by an Entergy affiliate, SERI. SERI sells its share of Grand Gulf to the Entergy operating companies under long term power supply contracts.

425. Entergy Mississippi does not own or operate a nuclear unit, but has a nuclear cost which is recovered through retail ratemaking, and payments made to SERI, pursuant to a Unit Power Sales Agreement (UPSA), which allocates 33% of Entergy's 90% interest in the Grand Gulf nuclear unit to Entergy Mississippi, and which has been approved by the FERC.

2. The Evidence Supports The Position Of The FERC Staff That The Nuclear Depreciation And Decommissioning Expenses Are Not Just And Reasonable

426. The undersigned finds the testimony of FERC Staff witness, Kevin Pewterbaugh to be highly probative on this issue (Exhibit No. S-8). Mr. Pewterbaugh's testimony is corroborated by testimony from Staff witnesses John Sammon and Janice Garrison-Nicholas (Exhibit Nos. S-18, S-12; Tr. at 2140-41 {Pewterbaugh}; Tr. at 2190 *et. al.* {Garrison-Nicholas}; Tr. at 2280 *et. al.* {Sammon}).

427. LPSC witness Lane Kollen also supports in large part the position of the FERC Staff (Exhibit No. LC-26). His testimony is probative to the extent that he

corroborates the FERC Staff position that Entergy's calculations are erroneous for establishing nuclear depreciation and de-commissioning expenses. His suggested recommendations, however, are largely found to be not suitable to correct the calculations for use in the Bandwidth formula, and are rejected.

428. The initial position of the LPSC was that the expected license extension duration should be used, as the LPSC has set sixty-year depreciation lives for River Bend and Waterford 3, based upon the belief that the current license duration will be extended. As previously indicated, the LPSC now agrees that the NRC granted license period is the correct depreciation rate which should be used.

429. The MPSC disagrees with the initial LPSC position pertaining to any proposed change that would extend Grand Gulf's nuclear unit depreciation and decommissioning expenses, based on an assumption that Grand Gulf will have its nuclear license extended in the future. In this regard, the MPSC's witness, Hugh Larkin, supports the FERC staff's position, that nuclear depreciation should reflect the actual life of the license duration (Exhibit No. MC-1 at 29), and his testimony is found to be highly probative.

430. As discussed more fully below, the recommendations of Mr. Pewterbaugh are adopted and found in accord with Commission precedent, although the undersigned finds and agrees with the LPSC that a new depreciation study is not needed prior to Entergy re-calculating the nuclear depreciation, based upon the NRC license extensions for ANO 1 and ANO 2, and using the license duration period for the remaining units. Moreover, as indicated, the undersigned finds the testimony of Mr. Kollen for the LPSC to be probative on this issue pertaining to depreciation and de-commissioning expenses used for ANO 1 and ANO 2.

431. Mr. Kollen testified that the APSC's failure to lower the depreciation rate by extending the service lives to sixty years, since the NRC has extended the service lives of these units to sixty years, is erroneous and is a disservice to the present generation of Arkansas ratepayers who are paying higher rates now (Tr. at 1745-49 {Kollen}).

432. He further testified that the previous depreciation life of 40 years was in fact based upon the licensure durational status as originally set by the NRC (Tr. at 1748 {Kollen}). Mr. Kollen testified that it is very unusual and in his opinion improper to have inconsistent decommissioning and depreciation rates as set by the APSC relating to ANO 1 and ANO 2 (Tr. at 1749 {Kollen}).

433. Mr. Tyler Tibbets, an accounting expert for the APSC also testified that it was his understanding that the original forty-year depreciation lives for ANO 1 and ANO 2 were based upon the NRC licenses (Tr. at 1901 {Tibbetts}). This fact

is further established by a 2001 depreciation review performed by the accounting firm of Deloitte & Touche on behalf of Entergy Arkansas, covering the period through December 31, 2001 (Exhibit No. LC-161 at 15). No evidence to the contrary was presented.

434. The undersigned rejects all other testimony given by Mr. Tibbetts on the nuclear depreciation issue as he has no training nor experience as a depreciation expert in this context, has never been qualified in any proceeding as a depreciation expert, and admitted he is not comfortable discussing this issue (Tr. at 1900-01{Tibbetts}). Therefore, Mr. Tibbett's testimony which criticizes Mr. Kollen's testimony is rejected.

435. The testimony of Entergy witness Bruce Louiselle made several points which also corroborate the concerns of Mr. Sammon and the position of the FERC staff. For instance, he agreed in part with Mr. Kollen and testified that using an improper accelerated depreciation rate will inequitably impact present and future generation of ratepayers, an important concern to the FERC Staff (Exhibit No. ESI-50 at 11; Tr. at 1208 {Louiselle}).

436. He also admits that this area is ripe with potential for providing incentives for Retail Regulators to attempt to manipulate payments made under the Bandwidth formula, implicitly acknowledging that the APSC's use of the 40 year nuclear depreciation greatly benefitted its position pursuant to the ultimate Bandwidth calculation (Tr. at 1210 {Louiselle}). Mr. Louiselle's admits he is aware that the FERC has in the past determined depreciation expenses for nuclear units should be in accordance with the nuclear licensure period as set by the NRC (Tr. at 1212 {Louiselle}).

437. Mr. Louiselle further admits that no adequate depreciation study has been performed by Entergy within the last ten years, which supports the inconsistent depreciation expenses it used in the Bandwidth calculations (Tr. at 1132-33 {Louiselle}). In response to questioning by FERC staff, he further acknowledged that he knew FERC precedent had set depreciation in accordance with the duration of the nuclear license.

438. He expressly acknowledges that the filed and lawful tariff, the Service Schedule MSS-3, Section 30.12, authorizes the FERC to assert jurisdiction and to set nuclear depreciation and decommissioning expenses, if it decides to do so (Tr. at 1212 {Louiselle}).

439. In his testimony, Mr. Pewterbaugh makes several important points which are summarized below (Exhibit No. S-8): First, the remaining life of a facility is the time between the present and its estimated retirement date. It is over this

period of time that depreciation and decommissioning expenses are spread and collected from ratepayers.

440. Where the remaining life has been extended pursuant to the NRC extending the license and the corresponding depreciation and/or decommissioning expense is not decreased, the recovery costs are collected "too quickly," with earlier ratepayers paying a disproportionately higher rate than later ratepayers, leading to what Mr. Pewterbaugh described as "inter-generational inequity" (Exhibit No. S-8 at 10). As indicated, most of the testifying experts validate this point.

441. Conversely, where the remaining life has not been extended pursuant to an approved license extension by the NRC, but the depreciation and decommissioning expense is treated as such, based upon an expected granting of the license in the future by the NRC, or otherwise, the depreciation and decommissioning expense will incorrectly occur for a longer period of time, again impacting later rate-payers.

442. Second, it is his view that the Commission has previously determined that the remaining life for nuclear units pertaining to both depreciation and decommissioning, is the actual remaining term of the license issued by the NRC.

443. Mr. Pewterbaugh, citing pertinent case law,[200] rejects the recommendations of LPSC's witness Lane Kollen on the point that the remaining life should be based upon expected license extensions and that decommissioning costs should be reduced to zero dollars. Mr. Pewterbaugh believes this is inconsistent with Commission precedent, especially where no new decommissioning study has been accomplished to support such a reduction.

444. Mr. Pewterbaugh recommends that all of the Entergy nuclear units be treated on a consistent basis. He therefore believes that the already established precedent be followed, and that the depreciation and decommissioning expenses be based upon the remaining life as determined by the duration of the license. He opines that units ANO 1 and ANO 2 should reflect the approved license extension for both decommissioning and depreciation.

445. For Waterford 3 and River Bend, the service life should also be based upon the original license approval and expiration dates, and should not use a speculative license extension date.

446. In Mr. Pewterbaugh's opinion, the decommissioning level should not be reduced to zero (Exhibit No. S-8 at 15) on the basis of the six-year old study

[200] *Boston Edison Company*, 59 FERC ¶ 63, 028, at 65,238 (1992).

presented to date. He also questions whether a zero level should ever be set unless the decommissioning fund is sufficient to cover all necessary current expenses involved with decommissioning of a nuclear unit.

447. The Commission has indeed previously held that nuclear depreciation and decommissioning expenses should be consistently measured by the remaining life left in the license set by the NRC. Any other measure would be purely speculative and might result in what Mr. Pewterbaugh describes as “inter-generational inequity.” In *Boston Edison Company,* supra, the Commission stated:

> The Commission consistently bases depreciation costs on the license life of a nuclear plant. (See, *Boston Edison Company*, 52 FERC 61,010,p 61,076, fn 57 (1990) (“The service life of a nuclear plant is dictated by its license life”)). The Commission recently reaffirmed this position in *Indiana & Michigan Municipal Distributors Association*, 59 FERC 61, 260 (June 3, 1992): “it would be inappropriate to base depreciation or decommissioning expense recovery on a period other than that specified in the existing NRC license”(Slip Op.at 30).[201]

448. The Commission has further stated in another proceeding involving Boston Edison Company:

> While Boston Edison’s application to extend the license may indicate Boston Edison’s belief concerning the plant’s potential operating life, Boston Edison does not have the final say in this matter. The NRC does. We will not base our decision upon speculation regarding possible changes in the license life of Pilgrim 1. We expect, however, that Boston Edison will make an appropriate section 205 filing if and when the NRC modifies Pilgrim 1’s operating license.[202]

449. The undersigned finds that only by following the cited precedent and adopting the FERC Staff position, will there ever be any consistency in establishing appropriate expenses for nuclear depreciation and decommissioning, for purposes of determining the Bandwidth calculations.

450. Furthermore, establishing consistency prevents the potential for abuse

[201] *Id*.

[202] *Boston Edison Co*., 52 FERC ¶ 61,010 at 61,079 (1990).

within retail rate setting jurisdictions for manipulating these expenses in order to manipulate payments within the Bandwidth calculations, as set forth in Mr. Louiselle's testimony (Exhibit No. ESI- 50 at 17). This finding is further supported by the Commission in a recent decision reaffirming that nuclear depreciation should be consistent with the life of the NRC granted license.[203]

451. The undersigned agrees with the premise offered by FERC Staff witnesses Mr. Pewterbaugh and also John Sammon, that depreciation should be recovered equitably over the life of an asset so that the utility can recover its capital investment over the life of the asset and the ratepayers who take service from the asset contribute equitably to capital recovery, over the service life of the asset. (Exhibit No. S-18 at 4).

452. Moreover, the undersigned agrees with Mr. Pewterbaugh that if annual decommissioning expense is set at zero, when there is still a balance to collect, there would be an increased likelihood that later ratepayers will pay an unfair portion of the expense.

453. The undersigned also finds that unforeseeable circumstances, such as additional decommissioning costs which are not known at this time, could create an enormous financial burden upon later rate payers, if the decommissioning fund turns out to be under funded. In this day and age the potential from external events is real. Secure decommissioning funds need to be available when needed (Tr. at 2181-82 {Pewterbaugh}).

454. As indicated, the undersigned finds the corroborating testimony of Mr. Sammon and Ms. Garrison Nicholas to be probative on this issue. Mr. Sammon testified that he disagrees with LPSC's witness Mr. Kollen, who asserts that Entergy failed to properly follow the methodology in ETR-26 and ETR-28, when reporting nuclear depreciation and decommissioning expenses (Exhibit Nos. S-18 at 18-19, ESI-8).

455. Mr. Sammon examined the filing methodology and explained the impact that differing depreciation and decommissioning expenses have upon the Bandwidth calculations. As established through the FERC staff cross-examination of Mr. Louiselle, the Schedule Service Agreement MSS-3, Section 30.12 contains two provisions which address depreciation source data and nuclear depreciation expense. The first section of 30.12 reads as follows:

> NDE= Nuclear Depreciation and Amortization Expense associated

[203] *See Louisiana Public Service Commission v. System Energy Resources, Inc.*, 124 FERC ¶ 61,003 (2008); also at n.56.

> with (NPP) as recorded in Account 403 and 404 and Decommissioning Expense, as approved by Retail Regulators, unless the jurisdiction for determining the depreciation and/or decommissioning rate is vested in the FERC under otherwise applicable law. (emphasis added).

The second provision states:

> NAD=Nuclear Accumulated provision for Depreciation and Amortization excluding ARO associated with NPP above, as recorded in FERC Accounts 108 and 111 (consistent with the accounting relating to Statement of Financial Standards (SFAS) 143 approved by the retail regulator having jurisdiction over the Company, unless the FERC determines otherwise. (emphasis added).

456. Mr. Sammon explained that the nuclear depreciation and decommissioning rate used to determine an Operating Company's annual nuclear depreciation and decommissioning expenses must be the same as those used to compute the accumulated depreciation for the nuclear plant. The nuclear depreciation and decommissioning rates used to determine an Operating Company's annual nuclear depreciation and decommissioning expenses must also be the same as those used to compute an Operating Company's nuclear plant related ADIT.

457. Mr. Sammon further testified that while Entergy originally asserted that the second provision in the aforementioned tariff applies to only the Grand Gulf nuclear facility, he does not accept this explanation. He also stated it was his opinion that the FERC has the authority under the Federal Power Act[204] to establish all rates and charges in the System Agreement.

458. Mr. Sammon takes the position that there is a compelling need for FERC to establish the nuclear depreciation and decommissioning expenses that form the basis for the Entergy Operating Companies' nuclear power plant costs to assure consistency (Exhibit No. S-18 at 10).

459. As the FERC Staff points out, Entergy witness Louiselle expressly recognizes the jurisdiction of the FERC over depreciation and decommissioning expenses used within the Bandwidth calculations, and this authority is clearly set forth in the filed tariff as described above in the cited language within Service Schedule MSS-3, Section 30.12.

[204] 16 U.S.C. ¶ 791(a) *et. seq.*; ¶ 824 *et. seq.* (2008); also at n.4.

460. Furthermore, the undersigned finds Entergy's argument that it simply used the depreciation and decommissioning expenses determined by Retail Regulators, which is one method available under Service Schedule MSS-3, to be unpersuasive. The fact of the matter is clear that once the NRC granted the requested extension of the license by twenty years to ANO 1 and ANO 2, the depreciation expense should reflect the license extension.

461. The evidence is un-rebutted that the original forty year depreciation life was based upon the original forty-year license. No suitable reason was provided by Entergy or the APSC as to why the depreciation rate, which was originally based upon the NRC license, was not extended when the license was extended.

462. This is especially significant since no new depreciation study has been performed by Entergy to support a depreciation expense other than one tied to the NRC license period. Whether this was driven by a motivation to reduce Entergy Arkansas' payments within the context of the Bandwidth formula, or for other purposes, is not relevant, as Retail Regulators are free to establish whatever rates they believe are appropriate for their ratepayers.

463. In this regard, Mr. Sammon had previously testified rather bluntly that he believes the nuclear depreciation expenses for Entergy Arkansas' two nuclear units, ANO 1 and ANO 2, "may have been manipulated" for the purpose of reducing Entergy Arkansas' Bandwidth payments, but his opinions were clarified in revision testimony to lessen this allegation.

464. However, Mr. Kollen raised a similar concern at the hearing (Tr. at 1746 {Kollen}), and the matter was raised by the APSC in a pre-hearing motion to strike Mr. Sammon's testimony. The APSC has vehemently denied any improper motive to attempt to manipulate the Bandwidth calculation.

465. The undersigned finds no evidence of any improper motive by the APSC, and finds the reasons behind the APSC decision to keep the retail nuclear depreciation rate for ANO 1 and ANO 2, to be irrelevant to the issue at hand.

466. However, the undersigned finds, as astutely described by Mr. Louiselle, the potential for manipulation of the Bandwidth is a relevant factor for the Commission to consider and provides additional support for the FERC Staff position that consistency in setting nuclear depreciation expenses for purposes of calculating the Bandwidth formula, is essential in order to provide no incentive for manipulation.

467. Furthermore, as described by Mr. Sammon, by adopting Mr. Pewterbaugh's recommendation to use actual NRC license lives, the depreciation expenses for

River Bend and Waterford 3 will increase. This will likely cause a raise in Entergy Gulf States' and Entergy Louisiana's production costs as calculated by the Service Schedule MSS-3.

468. Additional corroborating evidence for Mr. Sammon and Mr. Pewterbaugh's position is further provided by Michael Majoros, the depreciation expert that the APSC withdrew as a witness in this proceeding. In his deposition (Exhibit No. LC-285), the LPSC counsel obtained critical admissions in a series of questions where the witness was provided hypothetical questions which mirror the facts in this case. Mr. Majoros candidly admitted that in his opinion, it is improper to "over-recover" depreciation expenses.

> Q. So I want you to assume the utility only has one nuclear plant that's accounted for in those accounts, and it's been life extended, but the utility, because it wants to accelerate its capital recovery, or for whatever reason, has not life extended its depreciation expense. It has reflected the life extension in determining the service life of the property. And I want you to further assume that the utility fully believes, absolutely believes that the service life has been extended. Is it reporting the correct amounts for depreciation?
> A. No.
> Q. Why not
> A. Because it's using a life that's too short.
> Q. What's wrong with that?
> A. It's over-recovering depreciation expense.
> Q. What's wrong with that?
> A. What's wrong with that?
> Q. Yes.
> A. They're over-recovering depreciation expense. That's what's wrong with that.
> Q. What's wrong with over-recovering it? Is it {not} fair to Ratepayers?
> A. Absolutely.
> Q. Is it likely to produce intergenerational inequity? Is it disgusting from a consumer advocate point of view?
> A. Absolutely. It's horrible. Yes, it is, all of those things.
> Q. it's horrible?
> A. Absolutely

(Exhibit LC-285 at 64-65).

469. Finally, FERC staff witness, Ms. Garrison-Nicholas testified from an accounting viewpoint and clarified the Commission's accounting requirements set

forth initially in Order 618. She opined that New General Instruction 22, USOA[205] requires electric utilities to use, for accounting purposes, methods of depreciation that allocate the cost of utility property over its useful service life in a systematic and rational manner. The regulation reads as follows:

> A. Method. Utilities must use a method of depreciation that allocates in a systematic and rational manner the service life of the property.
>
> B. Service lives. Estimated useful service lives of depreciable property must be supported by engineering, economic, or other depreciation studies.
>
> C. Rate. Utilities must use percentage rates of depreciation that are based on a method of depreciation that allocates in a systematic and rational manner the service value of depreciable property to the service life of the property. Where composite depreciation rates are used, they should be based on the weighted average estimated useful service lives of the depreciable property comprising the composite group.[206]

470. Ms. Garrison-Nicholas testified further that the regulation provides no authority for utilities to change depreciation expenses reflected in FERC jurisdictional prices charged for power sales or transmission services, without a section 205 or 206 filing.

471. Moreover, she believes that the Commission has established uniform accounting and financial reporting requirements for the recognition and measurement of liabilities arising from retirement and decommissioning obligations of tangible assets with long life spans, and related costs for public utilities and licensees, natural gas, and oil companies.

472. General Instruction 25, to the USOA[207] requires an electric utility company with an asset retirement obligation to recognize the liability and to reflect an associated asset retirement cost at the fair value of the asset retirement obligation, in the period in which the obligation is incurred.

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[205] 18 C.F.R. Ch.1, PT. 101, at 363 (2007).

[206] *Id.*

[207] *Id*. at 407.

473. The electric utility company must initially record a liability for an asset retirement obligation in Account 230 (Asset Retirement Obligations), and charge the associated asset retirement costs to electric utility plant and non-utility plant, as appropriate, related to the plant that gives rise to the legal obligation. The asset retirement cost must be depreciated over the useful life of the related asset that gives rise to the obligation (Exhibit No. S-12 at 5-6).

474. She opines that the Commission's accounting regulations in her opinion therefore require an electric utility company to depreciate its asset retirement costs associated with nuclear production plant investment in a systematic and rational manner over the service life of the related property.

475. Moreover, in Ms. Garrison-Nicholas' opinion, an electric utility company should not change a depreciation expenses for FERC rate purposes without a section 205 or 206 filing. This requirement applies to both depreciation of tangible plant assets and asset retirement costs, which includes in her opinion, nuclear decommissioning costs (Exhibit No. S-12 at 7). She believes Entergy has failed to comply with these requirements.

3. Entergy's Jurisdictional Claims

476. Entergy's Briefs and position at the hearing, question FERC's jurisdiction to determine nuclear depreciation expenses insinuating first, that the FERC's jurisdiction is limited since it does not have the authority, nor has it ever tried to change a retail rate already established by a Retail Regulator. Entergy infers that any order changing the depreciation and decommissioning expenses here will infringe upon the APSC's established retail ratemaking authority.

477. Second, from a practical standpoint, Entergy argues that is ill advised to order a change in the depreciation and decommissioning expense because it will cause innumerable practical difficulties to have to essentially comply with different rates, including having to maintain two separate accounting systems.

478. The undersigned sees no jurisdictional issue in this proceeding, since the FERC Staff is not seeking to set retail rates. The FERC has jurisdiction to set rates over the sale of wholesale electricity and has jurisdiction over all aspects of the Bandwidth formula and underlying costs. It has historically and continues to exercise jurisdiction over the Entergy System which operates in multiple states pursuant to a single system agreement, and likewise has jurisdiction over the Mississippi UPSA.

479. The FERC has already exercised its authority under the Federal Power Act when issuing Opinions 480 and 480-A. A recent Supreme Court case has

reaffirmed the Commission's extensive jurisdiction in the wholesale market.[208]

480. The Commission is simply not bound to follow a state commission's considered judgment with respect to either accounting or ratemaking.[209]

481. Entergy presented no case on point for the proposition that the FERC does not have jurisdiction to reach the underlying costs, including nuclear depreciation expenses, used by Entergy in calculating the Bandwidth formula. Moreover, the filed and lawful rate (Service Schedule MSS-3, section 30.12) which governs the Entergy Systems Agreement expressly provides the FERC has jurisdiction to reject nuclear depreciation and decommissioning expenses set by Retail Regulators and to determine its own.

482. While the undersigned to some extent recognizes the validity of Entergy's second point, the practical difficulties, the FERC's chief concern is to ensure the Entergy Operating Companies are appropriately achieving rough production cost equalization, and that Entergy's compliance filing is just and reasonable, non-discriminatory and non-preferential, and thus must act to ensure compliance with Opinions 480 and 480-A.

483. While it can easily be said that the APSC's failure to readjust the depreciation expenses when the NRC granted the license extension does not comport to any reasonable accounting standard or established FERC precedent,

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[208] *Morgan Stanley Capital Group, Inc. v. Public Utility District No. 1 of Snohomish County*, 128 S.Ct. 2733 (2008); also at n.194 (noting that Commission has authority to regulate the wholesale of electricity in interstate commerce and that such rates are to be just and reasonable); *See also, Entergy Louisiana, Inc. v. Louisiana Public Service Commission, et. al.*, 123 S. Ct. 2050 (2003) (holding that under the filed rate doctrine, FERC approved cost allocations between affiliated energy companies may not be subjected to reevaluation in state ratemaking proceeding, where public utilities share capacity pursuant to interstate Entergy System Agreement, the allocation of costs of maintaining capacity and generating power constitutes the sale of electricity at wholesale in interstate commerce); *Southern Company Services, Inc.*, 123 FERC ¶ 61,204 (2008) (citing with approval historical precedent defining its exclusive authority over wholesale power sales and reiterating its position that ratemaking methodology proposed at the retail level does not govern the Commission's determination of the appropriate ratemaking methodologies to be used in developing wholesale rates).

[209] *See Kentucky v. FERC*, 760 F.2d. 3121, 1327 (D.C. Cir. 1984); *Houlton Water C.*, 60 FERC ¶ 61,141 at 61,515 (1992).

nor did any party present any evidence as to the reasoning for maintaining a forty-year depreciation life, the APSC can readily for retail rate purposes establish whatever rate it deems appropriate.

484. However, for purposes of the Bandwidth calculations and wholesale rates, the FERC has the final say over what constitutes a just and reasonable rate and has the authority to require consistent nuclear depreciation expenses for purposes of determining the Bandwidth formula. That authority in this case is expressly spelled out in the Service Schedule MSS-3 tariff.

4. The LPSC Position

485. Likewise, the LPSC agrees that any rate must meet the just and reasonable standard and that the arguments of Entergy, the APSC, and now the MPSC, do not justify acceptance of an unjust or unreasonable rate, just because one method set forth in the tariff allows for the input of nuclear depreciation expenses within the Bandwidth formula as set by the Retail Regulators. The FERC Staff joins in this argument.[210]

486. The LPSC rebuts the APSC's argument that by correcting the 2006 test year will harm Arkansas rate payers. The LPSC also disputes Entergy's assertion that requiring consistent nuclear depreciation expenses set in accordance with the NRC lives will result in de facto retroactive ratemaking. Rates set in this proceeding are prospective, and depreciation payments made at retail in 2006 eliminated capital obligations ratepayers would otherwise have to pay at retail in the future, ensuring they will be made whole.

487. According to the LPSC, the only way to ensure ratepayers on the Entergy System are protected is to use correct service lives for the nuclear units in every year of the Bandwidth calculation. Using inconsistent depreciation expenses, which Retail Regulators may change, would be unfair to ratepayers and represents a far greater potential for harm.[211]

488. The LPSC also asserts that no new depreciation study is needed to recalculate nuclear depreciation expenses and points out that Entergy conducted no new study to support the nuclear depreciation expenses determined by the APSC.

489. The undersigned finds the position of the LPSC to be persuasive. The

[210] LPSC RB at 24; FERC Staff RB at 19.

[211] LPSC RB at 24-25.

undersigned agrees with the LPSC and the FERC Staff that the filed rate doctrine and the rule against retroactive ratemaking arguments are not applicable here, as the depreciation expenses only applies to the Bandwidth formula and has no effect on depreciation rates set by Retail Regulators. Furthermore, when accepting Entergy's filing, the Commission's Order clearly stated that the filing was accepted subject to refund. Entergy and the APSC were fully advised of the refund obligation in the hearing order. Moreover, no new depreciation study is necessary to recalculate the depreciation expenses to reflect the NRC granted extension. The original depreciation rate for AN0 1 and AN0 2 was based upon the NRC granted license. To use a different methodology to establish depreciation expenses arguably dictates that Entergy should have done a complete depreciation study before accepting the expense set by the APSC. Therefore, this argument by Entergy and the APSC is not persuasive.

5. Summary

490. In summary, the undersigned finds the FERC clearly has the authority pursuant to the Federal Power Act to determine the depreciation and decommissioning expenses for the Operating Companies participating in the interstate Entergy Systems Agreement, used to calculate and ultimately determine the payments and receipts pursuant to the Bandwidth formula, as previously ordered by the Commission in Opinions 480 and 480-A. Moreover, Entergy's own lawfully filed tariff recognizes the FERC's authority as set forth in Service Schedule MSS-3, which clearly provides that the FERC may step in and determine nuclear depreciation and decommissioning expenses.

491. In support of this finding, the undersigned finds the testimony of the FERC Staff witnesses and LPSC witness Mr. Kollen, to be highly probative on this issue. Their testimony is consistent with the totality of the evidence and Commission precedent.

492. Entergy's nuclear depreciation and decommissioning expenses are not just and reasonable, and are inconsistent with FERC precedent. The undersigned adopts the recommendations of FERC staff witness, Mr. Pewterbaugh. Entergy must recalculate the nuclear depreciation and decommissioning expenses for the applicable Operating Companies and readjust the Bandwidth calculation in accordance with the aforementioned recommendation of Mr. Pewterbaugh and this decision, to reflect the actual operational life as determined by the NRC granted license, to include any granted extensions (Exhibit No. S-18).

493. The undersigned also agrees with the LPSC that no new depreciation study is required prior to making the nuclear depreciation recalculations, as it is not necessary and because the depreciation expenses had previously been determined

based upon the duration of the NRC license.

E. Net Area Load Variable Issue

494. **ISSUE:** What should Entergy have used as the source data for variable "ER" for the 2006 Bandwidth calculation (the "Net Area Load Variable" issue?

495. Net area load is the basis on which the Entergy System's variable production costs are allocated to each of the five Entergy Operating Companies.

496. The LPSC alleges Entergy erroneously used the wrong values to determine the net area loads variables, by using data from FERC Form 1, and that this method does not comply with ETR-26 and ETR-28. Entergy, the APSC and the MPSC essentially argue that Entergy's calculation is consistent with ETR-26 and ETR-28, because FERC Form 1 data is derived from the same source data set forth in ETR-26 and ETR-28. Entergy, APSC and the MPSC also assert this issue should be governed by Service Schedule MSS-3, which was changed in a compliance filing to expressly allow for the use of FERC Form 1 data.

497. Entergy witness Bruce Louiselle, FERC Staff witness John Sammon, APSC witness Dr. Keth Berry, and LPSC witness Stephen Baron, all agree that Entergy's use of FERC Form 1 data is the necessary method to reach an accurate result under the Bandwidth formula.

498. The undersigned finds the testimony of Mr. Louiselle to be highly probative on this issue, as corroborated in part by APSC witness Dr. Berry and FERC Staff witness, John Sammon.

499. Net area loads (calculated in terms of megawatt-hours (MWh) is the basis on which the system's variable production costs are allocated to each Operating Company, pursuant to the Bandwidth calculation. For example, if the system's total net area load (total energy) is 100 MWh, and one of the Operating Company's net area load is 20 MWh, for purposes of calculating the Bandwidth payments and receipts, the Operating Company would be allocated a 20% share of the system's production costs.

500. The net area loads reflected in the Bandwidth calculation by Entergy came from page 401 of the Form 1, "Electric Energy Account" (Exhibit No. ESI-11). The data is also contained in Entergy's general ledgers. The LPSC asserts that all of the net area loads values should be taken from the ISB data instead of the Form 1, because this was the methodology contained in ETR-26 and ETR-28.

501. All parties agree that by using the ISB data to create the energy allocator (ER) for computing production costs will produce incorrect results if an Operating

Company made “joint account” off system sales. This is why Entergy used data supplemented from the FERC Form 1.

502. The ISB is a monthly after the fact billing to the separate companies pursuant to Service Schedule MSS-3. It provides data on a monthly basis relating to transactions among the Operating Companies. As indicated it is important to note that certain data from the ISB is recorded in the general ledgers, which in turn is also used to prepare the Form 1 (Exhibit No. ESI- 6 at 45), thus some of the information from the FERC Form 1 is the same information from the ISB.

503. The ISB is and was used to determine the values which are reflected on page 401 of Form 1, but certain data, such as purchases from qualified facilities (QF Puts) do not come from the ISB. The LPSC asserts that the variable “ER” in the Bandwidth calculation should be equal to the values appearing in the ISB for “TO NET AREA.”

504. The LPSC position is that the calculations used in formulating the ETR-26 and ETR-28 were performed using data from the ISB, and that this is the methodology the Commission requires Entergy to use for determining net load in the Bandwidth calculation, without exception. Mr. Louiselle points out that when he drafted the ETR-28, it was based upon data for the twelve month period ending August 31, 2002, for which there was no Form 1 data, because the Form 1 data is available only on a calendar year basis. For the ETR-26 (summary), the data used to formulate this document was obtained, primarily, but not exclusively from the ISB data (Exhibit No. ESI-6 at 37).

505. As Mr. Louiselle describes that using the values reflected in the ISB data verbatim, will cause incorrect calculations and result in disparities in the bus bar production costs, and an incorrect Bandwidth payment/receipt schedule (Exhibit No. ESI-6 at 37). He explains this is because of how the Service Schedule MSS-3 and net value contained in the ISB, relate to non-requirement (non-RQ) sales.

506. Since Operating Companies have an obligation to meet energy needs of retail customers and wholesale customers (for which they have a tariff obligation), wholesale sales are referred to as “requirement sales.”

507. However, during times when an Operating Company may have excess capacity beyond their requirement sales, they may sell surplus energy in the wholesale market. These are referred to as the non-RQ sales. In the ISB the net area is determined based upon a coincident hourly basis measuring the demand for each Operating Company and the total load for the system by each hour. This measures the “responsibility ratio” for each Operating Company.

508. The purpose is to measure the requirements for each Operating Company. In calculating the value for the net area in the ISB, certain transactions are excluded, such as sales pursuant to unit power sales agreements, exchange energy, inadvertent energy, firm sales, unaccounted for energy and joint account system sales.[212]

509. Therefore, calculating the net area as reported by the ISB includes non-RQ sales by individual Operating Companies. An Operating Company making such short term obligation sales has the cost burden of Service Schedule MSS-1, reserve equalization and MSS-2, transmission equalization, associated with these transactions.

510. The allocation of these burdens to the particular Operating Company making such sales, pursuant to the aforementioned MSS-1 and 2, is accomplished by including that load in the "net area" value used in the ISB to calculate the appropriate responsibility ratio.

511. The value used for determining net area loads in the Bandwidth calculation pursuant to Service Schedule MSS-3, must be consistent with the actual dollars associated with the non-requirement sales. Pursuant to Section Service Schedule MSS-3, Section 30.13 (Exhibit No. ESI-8), the net area load (variable "ER") is used to allocate the variable production costs of the system to each Operating Company.

512. Variable production costs are the net of the revenues received from non RQ sales. Revenue credits (variable "RC") is a required input in the Bandwidth calculation, pursuant to Service Schedule MSS-3, Section 30.12 (Exhibit No. ESI-8), and is defined as revenues received from customers outside an Operating Company's net area and is recorded as production services in Account 447.

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[212] UPSA sales are excluded because that energy is not available to serve the Operating Companies' customer loads. Exchange energy (reflected in Service Schedule MSS-3), is excluded its transactions sum to zero on a system-wide basis. Sales among Operating Companies equal purchase, and therefore, do not affect the system's peak demand, nor affect loads of any individual company. Inadvertent energy is the imbalance among control areas and is a use of energy not available to serve individual company's load requirements. Firm sales are those which there is a demand charge, but the energy used to meet that load are unavailable to serve an Operating Company's load requirements. System (joint account) sales are on an opportunity basis. Unaccounted for energy constitutes a balancing account so that sources and uses are equal.

513. As Mr. Louiselle establishes in his testimony, net area load values and non-RQ sales need to be "in sync," or the allocation of the variable costs would be incorrect. In other words, to accurately reflect allocated production costs and to avoid this potential synchronization error which would artificially create disparities, use of the FERC Form 1 data is necessary. Mr. Louiselle continued to show that Entergy utilized good accounting practices by comparing the net area values, using only the ISB values, to the values used with an analysis under FERC Form 1.

514. The extent of the error if the LPSC position is adopted is great. Mr. Louiselle believes that the APSC would increase its Bandwidth payments by as much as $21 million. Below is a graphic illustration put together by Mr. Louiselle which supports his position that the methodology advocated by the LPSC would erroneously result in extensive over or under payments and skew the Bandwidth calculation.

515. For the results contained in Table 5, Mr. Louiselle used the net load value as shown in the ISB for the variable ER. In this scenario, he did not adjust the variable RC to be consistent with the variable ER, because he believes this is the method advocated by the LPSC in its protest.

TABLE 5 Bandwidth Payments and Receipts Based on Changing Variable ER to Reflect the To Net Area Per The ISB $ Millions [213]

Company	Payment	Receipt
EAI	$272.822	
ELL		$ 97.222
EGS		$133.456
EMI		$ 42.144
ENO		$ 0.000
Total	$272.822	$272.822

516. Mr. Louiselle also calculated ISB data that reflects consistent treatment of the variables ER and RC. Again, using this methodology skews the results, as graphically illustrated in Mr. Louiselle's Table 6, below. Here, Mr. Louiselle adjusted the variable RC to remove those revenues that are associated with the non-RQ sales included in the variable ER, where the variable ER is based on the "to net area" as reflected in the ISB.

[213] Exhibit ESI-6 at 48.

517. Under this method, Entergy Arkansas' payments are approximately $9 million lower and the receipts by the other Operating Companies are all lower as well. In Mr. Louiselle's opinion, relying on the ISB data to determine the variable ER and to calculate the variable RC on a consistent basis, would erroneously decrease payments and receipts, and jeopardize reaching rough production cost equalization.

TABLE 6 Bandwidth Payments and Receipts Based on Changing Variables ER and RC on a Consistent Basis $ Millions [214]		
Company	Payment	Receipt
EAI	$243.247	
ELL		$ 86.833
EGS		$119.527
EMI		$ 36.887
ENO		$ 0.000
Total	$243.247	$243.247

518. As indicated, the undersigned also finds the testimony of APSC's witness Dr. Keith Berry, to be highly probative on this issue. Dr. Berry substantially corroborates the opinions of Mr. Louiselle (Exhibit Nos. AC-1, AC-8). Dr. Berry supports Entergy's use of an energy ratio for Energy Arkansas that includes energy sales to its retail and wholesale customers, and which excludes the aforementioned opportunity sales, based upon the FERC Form 1 data.

519. Dr. Berry essentially agrees that the energy sales calculation should deduct the opportunity sales energy and demand from the Operating Company's energy and demand, or not make either of these deductions. Dr. Berry disagrees with LPSC's chief witness Mr. Baron that only the use of the IBS data should have been used.

520. In Dr. Berry's opinion, sole use of the data from the ISB would have caused blatant errors in the calculations. In essence, he supports the general position of Entergy, the APSC, and the MPSC, that even under ETR-26 and ETR-28, Entergy's calculations were consistent with (although not identical) to the methodology set forth in those documents. Commenting upon the magnitude of the synchronization error, Dr. Berry stated:

[214] *Id.* at 49.

> The energy shown in the ISB includes some opportunity sales made by EAI and is a larger number than the energy used just by EAI's Retail and Wholesale Requirements customers. If the ISB figure is used in the Bandwidth calculation, EAI's energy usage will increase and the effect will be to artificially inflate EAI's allocation of system variable production costs and increase EAI's 2006 Bandwidth payment by approximately $21 million…. Unfortunately, ETR-26 and ETR-28 included calculations that deduct opportunity sales revenues from EAI's production costs but fail to exclude the opportunity sales energy. No party to this Docket has disputed the fact that this calculation is wrong for ratemaking purposes. In supporting the ISB calculation of EAI's energy, LPSC witness Mr. Baron simply argues that Entergy should adhere to the methodology used in ETR-26 and ETR -28, however flawed. Removal of the opportunity sales energy from EAI's energy corrects that gross mismatch.

(Exhibit AC-8 at 22-23).

521. The undersigned also finds the testimony of FERC Staff witness John Sammon to be probative on this issue. Mr. Sammon confirms that use of the ISB data for the energy allocator in computing production costs will in fact produce incorrect results if an Operating Company made a "joint account" off system sale.

522. Mr. Sammons further testified that Entergy in Docket ER01-088, made changes to the ETR-26 and ETR-28,[215] the energy allocation methodology, which Entergy introduced through its proposed definition of variable "ER" in the Service Schedule MSS-3, Sections 30.12 and 30.13, and which the Commission has accepted, allowing use of FERC Form 1 data. He believes this is now the lawful rate and must be followed, even though he believes Entergy should have made a section 205 filing to makes this change (Exhibit No. S-1 at 5-8).

523. The LPSC argued at the hearing and in its Brief that this was done by Entergy with the intent to deceive the Commission, and that inadequate notice was provided by Entergy. Entergy disputes this assertion. No other party joins the LPSC on this issue.

524. The undersigned also finds it significant that Mr. Sammon recognizes Mr.

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[215] *See Louisiana Public Service Comm'n v. Entergy Services, Inc.*, 117 FERC ¶ 61,203 (2006); *Louisiana Public Service Comm'n v. Entergy Services, Inc.*, 119 FERC ¶ 61,095 (2007). These filings were respectively accepted by the Commission on Nov. 17, 2006 and April 27, 2007; also at nn.9, 10 & 40.

Louiselle used the ISB data to create the FERC Form 1 data. He acknowledges that the source of data used to develop the production cost disparities in ETR-26 and ETR-28 is part of the methodology, as directed by the Commission, giving some support to Entergy's position that even if it was required to follow ETR-26 and ETR-28 methodology, Entergy's calculations were generally consistent with those documents to the extent it could be without creating errors.[216]

525. The FERC Staff agrees with Entergy that there is an error embedded within the ETR-26 and ETR-28 methodology (Exhibit No. S-1 at 8-18), which would create an enormous error in calculating the Bandwidth formula, and that Entergy properly avoided this error.

526. In fact, the FERC Staff recognizes that Entergy's use of the FERC Form 1 data is the only appropriate approach to properly make the required calculation.[217]

527. As indicated in Mr. Sammon's testimony, the position of the FERC Staff is that the error was corrected when Entergy changed the ER allocator in its compliance filing (Exhibit No. S-1 at 25). While Mr. Sammon believes Entergy should have made a 205 filing, the FERC Staff now takes the position that since the Commission has already accepted the amendment to the compliance filing and allowed it to become effective, it is the lawful tariff and the contains the proper methodology. As a result, any calculation of "ER" now requires the use of the FERC Form 1 data.[218]

528. The MPSC and the APSC essentially support both the FERC and Entergy's position. It is significant that all parties, including the LPSC, recognize that using only the ISB data would create substantial errors in the Bandwidth calculations. The undersigned finds both Entergy's and the Staff's positions have merit.

529. Finding that the Commission intended Entergy to make filings which were just, reasonable, non-discriminatory and non-preferential, the undersigned finds the Commission inherently intended the Bandwidth calculations to be correct.

530. The totality of the evidence establishes that the Service Schedule MSS-3 was the lawful rate controlling the methodology used by Entergy to determine the

[216] Staff IB at 10.

[217] *Id.*

[218] As referenced above, FERC Staff further notes that Entergy subsequently made a separate section 205 filing on April 1, 2008, in Docket No. ER08-774-000.

variable ER allocator and that Entergy properly used data from FERC Form 1 to make its calculations.

531. Moreover, even if Service Schedule MSS-3 had not been changed to allow for use of FERC Form 1 data, the undersigned finds Entergy's methodology is nonetheless consistent (although not identical) with the methodology set forth in ETR-26 and ETR-28, since it is substantially derived from and sourced by the ISB data.

532. In support of this finding, the undersigned finds it significant that Mr. Louiselle's testimony establishes the data used was originally based upon the ISB data, derived from ETR-26 and ETR-28, and that Mr. Sammon acknowledges that use of this source data is consistent with the methodology pursuant to ETR-26 and ETR-28. While the FERC Staff doesn't agree with this reasoning, the undersigned finds this argument to be persuasive. In this unique situation, Entergy followed ETR-26 and ETR-28 as consistently as it could if it wanted to avoid substantial errors in the Bandwidth formula.

533. Moreover, since all parties acknowledge that using FERC Form 1 data is the only way to achieve a correct result, it makes little sense to order Entergy to re-compute the net area load variable requirements based upon ISB data which will create substantial errors and defeat the purpose of rough cost equalization.

534. Therefore, on this issue, the undersigned finds the net area loads data was correctly calculated by Entergy.

F. Remaining Accounting Issues

1. Account 165/Net Operating Loss Carry Back

535. **ISSUE:** What is the proper accounting for tax refunds expected to be received (and subsequently received) in 2006, for a net operating loss carry-back associated with Hurricanes Katrina and Rita, and whether those amounts included in Account 165 (Prepayments) on December 31, 2005, should be included in the 2006 Bandwidth calculation?.

536. Entergy Louisiana, Entergy Gulf States, and Entergy Mississippi, all suffered major storm damage losses as a result of the Hurricanes. Entergy was able to classify these losses as net operating loss carry-backs in order to request refunds of taxes made in prior years.

537. Entergy reflected the refund expectation as a receivable in the Entergy

Corporation Form 10-K in the "Prepayments and Other" line on its balance sheet as of December 31, 2005. Entergy also reflected this amount as a Prepayment in Account 165 in the applicable Operating Companies' FERC Form 1.

538. LPSC alleges, through the testimony of consultant Lane Kollen, that Entergy improperly excluded certain costs associated with Hurricanes Katrina and Rita, booked in Account 165 Prepayments, which should have been included in the Bandwidth calculation

539. The undersigned finds that Entergy properly calculated the balance of Prepayments, pertaining to Account 165, finding that these costs are associated with a NOL carry back that does not represent 2006 production costs and should therefore not be included within the Bandwidth formula.

540. The undersigned finds the testimony of MPSC witness Hugh Larkin, Entergy witnesses Theodore Bunting and Bruce Louiselle, and in part, FERC Staff witness Janice Garrison-Nicholas, to be highly probative in deciding this issue.

541. According to Mr. Larkin, the sole witness for the MPSC, Entergy properly exercised solid accounting practice and judgment to determine whether balances in the prepayment accounts represent the same type of prepayments previously incorporated in Exhibits ETR-26 and ETR-28, and properly assessed whether they are related or unrelated to production functions.

542. Mr. Larkin also agrees with FERC staff witness, Janice Garrison Nicholas, that the net operating loss carry-backs are more appropriately recorded in Account 143 (Other Accounts receivable), rather than Account 165, but that this difference has no impact on the Bandwidth calculation because Account 143 is also an account excluded from the Bandwidth formula (Exhibit No. MC-1).

543. In his view, Entergy exercised proper accounting practices and procedures, and followed a two prong test in determining what costs are calculated in the Bandwidth formula. First, a determination as to whether the cost is related to Entergy's production function must be made. Second, if so, a determination as to whether the amount is included in either wholesale or retail rates.

544. Mr. Larkin supports the MPSC position that the accounting issues raised by the LPSC are overly technical and would cost the Mississippi rate payers several million dollars, if adopted by the Commission (Tr. at 1969 {Larkin}).

545. Mr. Larkin opines that Entergy properly excluded the "tax recoveries" because they were not related to production functions. Moreover, he pointed out that Exhibits ETR-26 and ETR-28 were written before Hurricanes Katrina and

Rita occurred, and did not envision or account for these massive events, and that these tax refunds, in his opinion, are unrelated to the production function of Entergy. The undersigned finds Mr. Larkin's testimony to be supported by the totality of the evidence.

546. For instance, Mr. Louiselle testified for Entergy that Account 165 (Prepayments) are included within the Bandwidth formula as variable "P" and is equal to the average of the balances on Entergy's books at December 31, of the calculation year and December 31 of the prior year (Exhibit Nos. ESI-6 at 50, ESI-4, at First revised Sheet No. 48H).

547. An adjustment was made to remove the expected tax refund recorded in Account 165 from the calculation of production costs because the expected refund is a NOL carry back, not production items which should be captured within the Bandwidth formula (Exhibit No. ESI-50 at 39).

548. Entergy asserts it properly recorded the NOL carry backs in Account 165 as Prepayments[219] because the removal of the carry backs is consistent with ETR-26 and ETR-28 and is exactly what Mr. Louiselle did when developing ETR-26 and ETR-28, as shown when he removed the "Cajun Share," "prepayments related to the portion of the River Bend nuclear facility, that are not included in any Entergy Operating Company's regulated rates," from ETR-26 and ETR-28.

549. Mr. Louiselle points out that the principal behind the removal in both cases is the same; "Prepayments that are not related to the Entergy Operating Companies' production costs are removed from the Bandwidth Calculation."[220] The undersigned finds this reasoning persuasive.

550. Moreover, Mr. Bunting testified for Entergy regarding this issue and defended the accounting practice used by Entergy, noting that the accounting balance sheet reflecting the carry backs was December 31, 2005. He further recognizes that the amounts could have been recorded in Account 143, giving added validity to the FERC Staff's position.

> Q. Mr. Bunting in your opinion, ESI could have appropriately recorded the EOC's 2006 net operating loss carry back to one of three accounts in the Uniform System of Accounts; is that correct?
> A. I think that's what I previously stated, yes.
> Q. And those three accounts are Accounts number 165, which is

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[219] Entergy IB at 13-14

[220] *Id*. at 14.

> Prepayments, Account 143, which is Other Accounts Receivable, and Account 236, which is Taxes Accrued; is that correct?
> A. Correct.
> Q. And would you explain—why did you disagree with Mr. Kollen's rationale on this point.
> A. Because the carry-backs are not applicable to periods subsequent to the balance sheet date. The balance sheet date was December 31st, 2005. By their very nature, the carry-backs resulted in refunds, and in 2006, they were carried back

(Tr. at 873-74 {Bunting}).

551. The undersigned finds Mr. Bunting's testimony provides probative corroborating evidence on this issue (Exhibit Nos. ESI-5, ESI-44; Tr. at 871-74 {Bunting}).

552. The undersigned gave little weight to the testimony of LPSC witness Lane Kollen on this issue, as his proposed method of accounting would most likely have caused errors in the Bandwidth calculations, by preventing an analysis of whether particular transactions are truly related to production functions. The LPSC position would essentially cause disparities in the ultimate payment distribution to the Operating Companies.

553. Additional corroboration on this accounting issue was presented by APSC witness, Tyler Tibbetts, who supports Entergy's position and accounting practices. Mr. Tibbetts opines that Entergy properly recorded the NOL carry-backs in Account 165, under the circumstances when dealing with the extraordinary events of Hurricanes Katrina and Rita, although he too, would have used Account 143 (Exhibit No. AC-5 at 7).

554. Additionally, the FERC Staff is in agreement that these costs should not have been included within the Bandwidth calculation, although Staff argues that Account 143 is the proper account to reflect this item. Staff witness Janice Garrison-Nicholas testified that the amounts are clearly related to NOL carry back and are not production related. Although she believes the amount should have been recorded in Account 143, she agrees they should not have been included within the Bandwidth formula (Exhibit No. S-6 at 8).

555. The undersigned finds Entergy's accounting practices on this issue were made in compliance with the methodology directed by the Commission. The undersigned therefore finds Entergy properly excluded these tax recoveries from the Bandwidth formula, although Account 143 would have been the more appropriate account to have used.

2. Hurricane Storm Recovery

556. **ISSUE:** (a). What is the proper accounting for Hurricanes Katrina and Rita related damage costs, recoveries, related regulatory assets and regulatory liabilities? (b). How should Hurricanes Katrina and Rita related damage costs/recoveries be reflected in the 2006 Bandwidth calculation?

557. All of the Entergy Operating Companies, except Entergy Arkansas, suffered extensive storm damage from Hurricanes Katrina and Rita in 2005. The damage exceeded $1.5 billion, primarily causing damage to transmission and distribution systems.

558. In March 2006, the LPSC issued an order allowing for Entergy Louisiana and Entergy Gulf States to recover interim storm damage costs (Exhibit No. LC-41). In August 2007, the LPSC ordered permanent relief (Exhibit No. LC-196). Therefore, the interim storm recovery is at issue here for purposes of whether it should have been included in the Bandwidth formula.

559. Entergy accounted for interim storm damage recoveries as a debit to Account 407.3 (Regulatory Debits) and as a credit to Account 254 (Regulatory Liabilities).

560. The LPSC, through Mr. Kollen, contends that damages which exceeded the storm reserve should have accrued to Account 228.1 (Accumulated Provision for Property Insurance) and should be accounted for by amortizing excess losses to Account 924 (Property Insurance).

561. In essence, Mr. Kollen argues that Entergy failed to properly record all storm damage expenses associated with Hurricanes Katrina and Rita in Account 924, and therefore, failed to include these costs in the Bandwidth calculation. FERC Staff and the CNO join the LPSC to some degree, by asserting the interim storm damage should have been recorded in accounts, which to some degree or another are accounts included in the Bandwidth calculation.

562. Historically, utilities were unable to insure their transmission and distribution systems at reasonable rates since Hurricane Andrew in 1991. Regulatory entities in response began authorizing large annual accruals collected in rates which were being set aside in Account 228.1 to cover unforeseen future storm damages. In general, under normal anticipated accounting practices, storm reserve funds collected in the rates would be credited to account 228.1 and expenses debited in Account 924 (Exhibit No. MC-1).

563. Utilities recover only the level of storm insurance reserves included in the

rates. For excess losses, utilities would need to seek special treatment from the regulatory entities. These excesses could be handled in a special surcharge included in the rates.

564. Authority for collecting excess storm damages is authority for utilities to establish a "regulatory asset." Regulatory assets are generally recorded in a separate account and represent the storm damages incurred which exceeded the provision in Account 228.1 (Exhibit No. MC-1 at 20-23).

565. The regulatory asset is amortized to a regulatory expense account as revenues are collected. There is no expensing of these excess losses above the reserve balance to Account 924, since the recovery is not property insurance but that of a regulatory asset.

566. The only amount charged to Account 924 is the authorized accrual for property insurance. The property insurance expensed to Account 924 can only be charged by direction of the regulatory entity with authority over the utility (Exhibit No. MC-1 at 23-25).

567. The undersigned finds that under the existing circumstances Entergy properly accounted for interim storm recovery and exercised proper accounting practices. The undersigned finds the testimony of MPSC's witness Larkin, Entergy witness Bunting, and in part, FERC staff witness, Ms. Garrison Nicholas to be probative and to support this finding.

568. Mr. Larkin opines Mr. Kollen is simply incorrect. Based upon his knowledge and review of Commission directives and the USOA, no account should be credited to Account 228.1 unless authorized by a regulatory authority, "or authorities to be collected in a utility's rate levels."[221]

569. In other words, Mr. Larkin believes that only amounts which are authorized to be collected in rates may be credited and charged to Account 924. The damage from Hurricanes Katrina and Rita far exceeded the accumulated storm reserves in Account 228.1, in every jurisdiction.

570. Mr. Larkin believes that Entergy properly accounted for Account 924 in the sense that it did not understate the balance as advocated by LPSC. Mr. Larkin further testified, however, that he does believe Entergy erred by allocating a portion of Account 924 in the Bandwidth calculation. He believes this in effect allocates a portion of the transmission costs to the production function, unless it

[221] 18 C.F.R. Ch 1, PT 101, at 406 (2007).

can be verified that these costs actually shown to be damages to production facilities (Exhibit No. MC-1 at 25).

571. He recommends that the Commission direct Entergy to remove any balance in Account 924, which relates to accruals to Account 228.1, because these balances represent customer paid insurance relating to the distribution and transmission systems, not to production functions.

572. Mr. Larkin defended his opinions well at the hearing and displayed an extensive knowledge of accounting. Most notable is his recognition that Entergy's accounting involved extremely complex and sometimes unique situations, such as Hurricanes Rita and Katrina (Tr. at 1994-96, 2003-04 {Larkin}).

573. FERC staff witness Ms. Garrison Nicholas agrees with Mr. Larkin's testimony in large part, and joins him in criticizing the opinions of Mr. Kollen for LPSC. She testified that Mr. Kollen's opinion is not consistent with the Commission's adopted USOA.

574. Ms. Garrison Nicholas stated that in part, Entergy properly accounted for the storm damages since it properly reported the debit balances associated with storm damage costs in Account 182.3, under "Other Regulatory Assets," assuming the amounts are recoverable in future rates, and assuming Entergy reported these in its general ledgers as well as FERC Form 1, which Mr. Bunting indicated he had.

575. She, however, also believes that Entergy Louisiana did not correctly account for interim storm recovery in its use of Account 407.3 (Regulatory Debits) and Account 254 (Other Regulatory Liabilities). Ms. Garrison-Nicholas opines that Entergy should have recorded the interim storm recovery as debits to the specific expense accounts where the storm costs were originally recorded and a reduction to Account 182.3 (Other Regulatory Assets) as the interim storm revenues were recovered.

576. Mr. Bunting believes that the interim storm damage recovery was not property insurance or a reserve accrual, which would fall within the USOA definition Account 924. Mr. Bunting opines that Entergy properly accounted for the storm damage, emphasizing that LPSC authorized interim relief recovery for Hurricanes Katrina and Rita related costs for Entergy Louisiana and Entergy Gulf States. Mr. Bunting candidly described the unique situation involving accounting issues pertinent to Hurricanes Katrina and Rita (Tr. at 874 {Bunting}).

577. The interim relief was applicable for all storm costs, including distribution, generation and transmission. Mr. Bunting opines that it was proper accounting

practice, consistent with the USOA, to record interim storm recovery in Account 254. Mr. Tibbetts for the APSC essentially agrees with the accounting practices used by Entergy regarding this issue (Exhibit No. AC-5).

578. The undersigned agrees with Mr. Bunting in large part, that under the definition of regulatory assets and liabilities, Entergy properly accounted for interim storm recovery in Account 254 (Regulatory Liabilities) and Account 407.3 (Regulatory Debits), under the existing circumstances.

579. In support of Entergy's position, Mr. Bunting testified that the LPSC order granting interim storm recovery did not authorize Entergy Gulf States or Entergy Louisiana to charge amounts to Account 924 collected for storm reserve accruals.

580. The order stated that interim recoveries were the first part of a two stage process and that interim recoveries were subject to true up and refund when permanent rate recovery was to be determined in the second stage of the process (Exhibit No. ESI-44 at 4-6).

581. Additionally, the interim recoveries were later reflected in the determination of the permanent recovery. Mr. Bunting further testified that interim recovery was initially to be recovered through the fuel clause instead of base rates, providing further support that the recovery was not a charge to storm reserve accrual. From an accounting point of view, all of these factors convinced Mr. Bunting he was correct in not treating the interim storm damage as reserve accounting for storm damage.

582. Furthermore, the interim storm recovery included capital, non-capital and interest costs, with only a portion applicable to non-capital costs, which are the type normally charged to specific O& M accounts.

583. Since it was not ascertainable to distinguish what portion of the interim recovery was applicable to which component of cost, Mr. Bunting believes that use of a specific O & M account was not practicable.

584. Ms. Garrison-Nicholas recognizes this distinction and agreed that only the production related costs should be charged to traditional O&M type accounts (Tr. at 2199-2200 {Garrison-Nicholas}).

585. In sum, the undersigned finds the totality of the evidence supports the finding that Entergy properly accounted for interim storm damage. In accordance with Mr. Larkin's testimony, however, the undersigned further finds that Entergy should re-assess Account 924 and exclude any portion previously included in the Bandwidth calculation, which relates to accruals to Account 228.1, and which

does not relate to a production function.

3. ADIT Amounts

586. **ISSUE:** What accumulated deferred income tax (ADIT) amounts should have been included for the 2006 Bandwidth calculation?

587. LPSC contends Entergy improperly excluded federal income tax debit balances in Account 190 from the Bandwidth calculations and alleges that Entergy's removal of deferred federal income tax debit balances does not comply with the methodology used in ETR-26 and ETR-28.

588. The adjustment proposed by the LPSC is the single largest adjustment affecting Bandwidth payments received by the MPSC. The MPSC estimates that if the Commission were to accept this proposed LPSC adjustment, it would eliminate approximately 26% of the total Bandwidth payment of $40.6 million, calculated for Mississippi for 2006. An estimated amount of $10.4 million would be readjusted, largely to the benefit of the State of Louisiana (Exhibit No. MC-1).

589. Both Entergy and the MPSC assert that Entergy properly calculated ADIT for purposes of calculating the Bandwidth formula. Entergy also criticizes LPSC' primary witness, Mr. Kollen on this issue, for not describing any specific ADIT amount he believes was improperly calculated. Entergy argues Mr. Kollen's testimony is not probative because it is vague and lacks specificity.[222] The undersigned finds Entergy's arguments to be persuasive.

590. Entergy witnesses Mr. Louiselle, and Mr. Bunting, and MPSC witness, Mr. Larkin testified on this issue. Their testimony is found to be probative on this issue. Mr. Louiselle describes in detail the methodology Entergy used in making the ADIT exclusions (Exhibit No. ESI-50 at 41-47). Mr. Louiselle describes how all of the ADIT exclusions comply with the requirements of Section 30.12, Service Schedule MSS-3, which sets forth the types of ADIT amounts which should be excluded from the Bandwidth calculation. This is the controlling methodology for this issue (Exhibit Nos. ESI-50 at 41-47; ESI-6 at 56-59; ESI-44 at 18-19).

591. Mr. Bunting testified how Entergy recorded the ADIT for book and tax purposes (Exhibit No. ESI-44 at 18). Mr. Larkin provided additional corroborating testimony opining that Entergy properly excluded certain ADIT pursuant to the Service Schedule MSS-3, Section 30.12, which he also believes is the correct methodology.

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[222] Entergy IB at 19.

592. While LPSC takes the general position, that only Statement of Financial Accounting Standards (SFAS) 109 and Property Insurance Reserves, are excludable, Mr. Larkin believes the express language of the tariff found in Service Schedule MSS-3, extends the exclusions to other balances of a similar nature, and that Entergy's exclusions here followed proper accounting practices and was in compliance with Commission directives (Exhibit No. MC-1 at 18).

593. Mr. Larkin opines that excludable ADIT balances should apply to cost of service purposes or which arose as a result of retail rate making decisions. Mr. Larkin also points out that some of the excluded ADIT balances did not exist when Exhibits ETR-26 and ETR-28 were drafted (Exhibit No. MC-1).

594. LPSC also proposes to include $246 million of ADIT to SFAS 158 in production costs. SFAS 158, however, was not in effect until the fiscal year, ending in December 2006. The effect would substantially increase the rate base for production costs calculations. Mr. Larkin opines that the impact upon Mississippi rate payers would be substantial, and that Entergy properly excluded the ADIT amounts from the Bandwidth calculation.

> In my opinion the "including but not limited to" language would extend the exclusions to other balances of similar nature….It appears to me that the tariff as stated allows for the exclusions of deferred income tax balances which should not have been included for cost of service purposes or which have arisen as a result of retail ratemaking decisions. Additionally, there are deferred income tax balances which did not exist when the Commission adopted Exhibit ETR-26 and ETR-28 which are properly excluded from the production cost calculations.

(Exhibit No. MC-1 at 10).

595. Furthermore, Mr. Larkin testified that he reviewed the major balances which make up the debits that the LPSC seeks to include for production cost purposes within the Bandwidth calculation. In his opinion, none of the balances which he reviewed are related to production costs or are not included for ratemaking purposes, and were properly excluded by Entergy (Exhibit Nos. MC-1 at 14-18, MC-3).

596. Based upon all the evidence, the undersigned finds Entergy properly excluded the aforementioned ADIT from the Bandwidth calculation.

4. River Bend A &G

597. **ISSUE:** What method should be used to properly remove the administrative and general expenses (A&G) and Other Taxes associated with the 30% share of the capacity of the River Bend nuclear facility prior to the "functionalization" of such costs in the 2006 Bandwidth calculation?

598. The undersigned finds that Entergy did erroneously calculate the bus bar production costs for Entergy Gulf States pertaining to the River Bend 30% Unit, relating to the A&G costs. The undersigned finds the testimony of Mr. Randy Futral, a consultant for LPSC (Exhibit No. LC-42) to be highly probative on determining the error occurred.

599. Mr. Futral discovered a computational error in Entergy's May 29, 2007 Bandwidth Filing, which understated Entergy Gulf States' production costs for 2006. Entergy admits this error occurred. However, the undersigned finds the proposed remedy offered by Entergy is preferable to the remedy offered by the LPSC.

600. Essentially, as explained by Mr. Futral, Entergy inadvertently twice excluded from Entergy Gulf States' nuclear production expense the A&G expenses associated with the unregulated 30% portion of the River Bend nuclear unit, owned by Entergy Gulf States and operated by Entergy Operations, Inc., during 2006.

601. As he explains in his pre-filed testimony, Entergy's compliance filing not only removed from Entergy Gulf State's production costs the directly assigned A&G expenses in accordance with ETR-26 and ETR-28 ($7.959 million), it also removed an A&G expense amount of $9.264 million through the use of a labor ratio which had been adjusted to exclude labor for the River Bend 30% facility.

602. In its latest section 205 filing, Mr. Futral states that Entergy changed the factor to functionalize the A&G expense to production from a direct labor ratio to a labor augmented with affiliate labor ratio (LAWAL).

603. This LAWAL ratio contained labor dollars, not only attributable to each Operating Company's direct labor (as was the situation for ETR-26 and ETR-28), but also included labor billed from the two service companies serving the Operating Companies, ESI and Entergy Operations, Inc. (EOI), another subsidiary company. Instead of including all labor dollars billed from EOI, Entergy reduced the labor expenses in the LAWAL ratio by the labor associated with River Bend 30%.

604. In his opinion, Mr. Futral states that "combining this new LAWAL related adjustment with the specific manual adjustment for the River Bend 30 facility A&G, created a doubling effect of the A&G cost removals related to the River Bend 30%. (Exhibit No. LC-42 at 5-6). He believes that the two reductions in the A&G expense amounts to $17.223 million, more than twice the amount directly attributable to the River Bend 30% A&G costs (Exhibit Nos. LC-42 at 11, LC-46).

605. Mr. Futral believes the proper remedy is to increase Entergy Gulf States' production costs by $9.264 million to add back the costs removed for the River Bend 30% using the new LAWAL "functionalization" factor. In particular he asserts that the formula on Schedule A.4, line 115, should be changed so that the LAWAL ratio used to functionalize Entergy Gulf States' A&G expense, does not reflect the reduction for the River Bend 30%, in either the numerator or denominator.

606. This would result in a 59.99% "functionalization ratio." There would be no change to the $7.959 million in directly assigned costs, in order to be consistent with Entergy's treatment in ETR-26 and ETR-28 (Exhibit No. LC-42 at 11-12).

607. According to Mr. Futral, this results in an increase Bandwidth payment by Entergy Arkansas of $1.880 million. Entergy Gulf States would have its receipts under the Bandwidth formula increased by $5.838 million. Entergy Louisiana would have its Bandwidth receipts reduced by $2.523 million, while Entergy Mississippi would have a receipt reduction of some $1.435 million (Exhibit No. LC-42 at 7).

608. Entergy witness, Mr. Louiselle acknowledges the computational error and recalculated the Entergy Gulf States' bus bar production costs (Exhibit No. ESI-50 at 54-55).

> Yes. The A&G associated with the unregulated portion of River Bend (River Bend 30%) is an error. Attached is Exhibit ESI-54, which recalculates the EGS bus bar production costs and the effect of that on the Bandwidth calculation to correct this error.

(Exhibit No. ESI-50 at 54).

609. However, Mr. Louiselle disagrees with the methodology used by Mr. Futral to recalculate the effect upon the Bandwidth payments. Mr. Louiselle first subtracted the River Bend 30% from the total company's A&G and functionalized the residual amount. In the erroneous "as filed calculation," the total A&G was first functionalized using the labor ratios from the River Bend 30%, and A&G was then subtracted.

610. He believes that because the labor ratio used did not include the River Bend 30% labor, this is what caused the effect of deducting the River Bend 30% A&G twice. He made a similar adjustment to the variable "other taxes, which had a similar error (Exhibit Nos. ESI-50 at 55, ESI-54).

611. Mr. Louiselle did not use Mr. Futral's methodology because in his opinion, this methodology would require the use of two different labor ratios for Entergy Gulf States, and this would create an erroneous result. He believes that his re-calculation is correct and accurately "cures the problem in a manner consistent with how the A&G functionalization process works under the as-filed Bandwidth calculation," with a resulting proposed increase in Entergy Arkansas' total payments under the Bandwidth formula to $ 252,534.00 (Exhibit Nos. ESI-50 at 55, ESI-54 at A1).

612. The undersigned finds the remedy offered by Mr. Louiselle is based upon sound accounting practice and consistent with the overall filed methodology and directives by the Commission. Accordingly, this remedy is accepted over the methodology proposed by Mr. Futral.

5. Account 923/Outside Services Employed

613. **ISSUE:** Have costs been misclassified to Account No. 923, Outside Services Employed and, if so, how does that impact the 2006 Bandwidth calculation?

614. The undersigned finds that Entergy did commit errors relating to certain costs pertaining to Account 923. Entergy admits this error.

615. Account 923 (Outside Services Employed), is an account included in the Bandwidth formula under variable "AG," which is used in calculating the "Fixed Production Expense" component of "Actual Production Cost" (Exhibit No. ESI-4 at 48H).

616. FERC Staff witness Garrison Nicholas testified that Entergy recorded certain costs in Account 923 which are not consistent with the requirements of the USOA. She stated that many of the costs recorded apply to specific operational functions, other than administrative and general expenses.

617. She proposes that Entergy reclassify these costs and record them in an appropriate functional operation or maintenance expense accounts, or as otherwise directed by the USOA (Exhibit No. S-6). During discovery, Entergy produced a response which disclosed certain project descriptions of an operational nature, which were erroneously recorded within Account 923.

618. Because of the general descriptions, Ms. Garrison Nicholas could not identify the specific costs which should be re-classified. Ms. Garrison Nicholas recommended that the Entergy Operating Companies be required to analyze the costs recorded in Account 923 for 2006, and reclassify those costs to the appropriate account, pursuant to the USOA. Entergy should also correct the appropriate pages in their 2006 FERC Form 1 filings to the Commission.

619. Finally, Entergy Operating Companies should correct and submit revisions of its Bandwidth Filing to report the aforementioned changes (Exhibit S-6 at 12). Mr. Bunting essentially agrees with the position of FERC Staff. Subsequent to the pre-filing of Ms. Garrison Nicholas' testimony regarding this issue, Mr. Bunting ordered a comprehensive review, a summary of which he has made available (Exhibit No. ESI-46). Essentially, he found $6.6 million of the $62.4 million in Account 923 should be reassigned to other accounts.

620. The undersigned adopts the testimony of Ms. Garrison Nicholas and finds her recommendation for Entergy to reclassify the appropriate costs to other accounts, and as described in Exhibit ESI-46, is appropriate, but that Entergy has already sufficiently accomplished that recalculation. Accordingly, as set forth in Mr. Louiselle's testimony, Entergy has conducted the re-examination as recommended by Ms. Garrison Nicholas (Exhibit No. ESI-50 at 55).

621. While the FERC Staff recommends a further review of this issue (and the LPSC concurs in this request), it provides no specific information to indicate that Entergy's already accomplished review was not sufficient. Quite, the contrary, Mr. Louiselle describes how he oversaw the subsequent review, which was accomplished by two certified pubic accountants. Therefore, based upon the evidence, the undersigned finds the interest of finality dictates that further review is not warranted for this issue.

622. The revised Bandwidth calculation is attached as Exhibit ESI-55, which includes first re-calculating the aforementioned errors in Account 923, resulting in an additional payment of approximately $224,000.00 from Entergy Arkansas; $86,000.00 from Entergy Louisiana; $55,000.00 from Entergy Mississippi; and a payment of the corresponding $365, 000.00 to Entergy Gulf States.

623. Entergy New Orleans owes no payment, nor receives any, after the adjustment. In addition to the adjustments made pertaining to the River Bend 30 adjustment, Entergy Arkansas's Bandwidth payment, regarding these two accounting errors, increases to $252,758.00.

Bandwidth Calculation For the Year Ended 2006 ($Millions)[223]					
Item	EAI	EGS	ELL	EMI	ENO
Before A/C 923 Reclassification	$(252.534)	$122.659	$89.932	$39.943	$0
After A/C 923 Reclassification	$(252.758)	$123.024	$89.846	$39.888	$0
Change	$ (.224)	$ .365	$ (.086)	$ (.055)	$0

6. Spindletop Accounting Issue

624. **ISSUE:** How should EGS' costs of acquiring the Spindletop Gas Storage Facilities and the Spindletop Gas Storage Facilities regulatory asset have been accounted for? (b). How should EGS' costs of acquiring the Spindletop Gas Storage Facilities and the Spindletop Gas Storage Facilities regulatory asset-related costs have been reflected in the 2006 Bandwidth calculation?

625. The latter issue here is rendered moot by the Commission's order in Docket No. EL08-51-000, setting this issue for separate settlement and hearing proceedings, and for further decision as to whether or not the investment in the Spindletop regulating asset should be included in Entergy Gulf States' production costs.[224]

626. Moreover, the undersigned finds some merit with the position advocated by FERC Staff that the issue raised by the LPSC to include the Spindletop regulatory asset and related amortization in the Bandwidth formula is a change in the methodology to ETR-26 and ETR-28 because those accounts are not components in the Bandwidth formula.

627. As noted by FERC Staff, the Commission has previously ruled that changes in methodology must be made by section 205 or section 206 proceedings, and not within compliance filings. Therefore, this issue should not have been a stipulated issue in this case.[225]

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[223] Exhibit No. ESI-50 at 56.

[224] *Louisiana Public Service Commission v. Entergy Services, Inc.*, 124 FERC ¶ 61,010 at P 29 (2008); also at n.147.

[225] *Louisiana Public Service Comm'n v. Entergy Services, Inc.*, 117 FERC ¶ 61,203 (2006).

628. In any event, all parties apparently agree this portion of the Spindletop issue is moot. Thus, the undersigned will only decide the Spindletop accounting issues.

629. To this end, the undersigned finds that Entergy did properly account for the Spindletop Gas Storage facility. The Spindletop Gas Storage facility consists of caverns that were converted into an underground gas storage facility. This facility, with other pipelines and related equipment provide gas storage for Entergy Gulf States. Entergy purchased them in 2004 from Sabine Gas Transportation Co. (SGT).

630. Previous to that, Entergy purchased the storage service from SGT. Historically, from the early 1990s through 1996, Entergy Gulf States recovered costs billed to it pursuant to a fuel adjustment charge. Entergy Gulf States recorded all costs incident to the SGT contract to Account 501.

631. Mr. Louiselle for Entergy responded to LPSC's witness Mr. Kollen's assertions in the pre-filed testimony that this issue was inappropriately calculated in the Bandwidth formula (Exhibit No. ESI-50 at 23-25). The LPSC counters that Entergy has not followed proper accounting procedures by recording capital costs in Account 182.3 (Regulatory Assets) and amortization expense in Account 407.3 (Regulatory Debits).

632. FERC Staff witness Garrison Nicholas testified that she believes Entergy correctly recorded the items, which she described as proper regulatory assets, in Account 182.3. She opines, however, that Entergy erroneously accounted for the amortization of regulatory assets in Account 407.3. She believes those assets should be recorded in Account 501 (Exhibit No. S-12 at 15-16).

633. Mr. Louiselle and Mr. Bunting satisfactorily rebut Ms. Nicholas' opinion relating to the Account 407.3. Mr. Louiselle believes it is inappropriate to also reflect in Account 501, costs that were incurred during a prior period. He feels that this would result in confusion (Exhibit No. ESI-50 at 25-26).

634. Mr. Bunting testified that LPSC had ordered Entergy Gulf States to refund to Louisiana rate-payers certain costs associated with the Spindletop facility that LPSC had determined were capital related and previously recovered through the fuel adjustment clause from Louisiana rate-payers.[226]

635. The refunds were determined by LPSC to be a regulatory asset and

[226] LPSC Order No. U-19904 D (Oct. 7, 1996).

amortized over forty years. In his view, Account 501 does not allow for inclusion of regulatory assets. He also believes that since the Spindletop regulatory asset was established through the use of Account 407.3, this was the most appropriate account to use to amortize the asset (Exhibit No. ESI-44 at 17).

636. The undersigned finds the testimony of Mr. Bunting to be probative on this issue. Entergy utilized reasonable judgment in accordance with sound accounting practice. The undersigned finds no error in how Entergy accounted for the Spindletop costs.

7. Waterford 3 Issue

637. **ISSUE:** How should the ADIT allocated for purposes of the 2006 Bandwidth calculation reflect the Waterford 3 Sale/Leaseback?

638. This issue is also moot due to Entergy's change of position on this issue in Docket No. EL08-51-000. In that proceeding, the LPSC filed a section 206 Complaint seeking amendments to the Bandwidth formula, including an amendment for treatment of certain ADIT associated with the Waterford 3 nuclear generation unit. Entergy did not oppose the Waterford ADIT amendment.

639. The Commission granted the LPSC's request to amend the formula to remove the Waterford ADIT amounts, effective March 31, 2008.[227] Entergy argues that this action fully adjudicates this issue which must be dismissed as a matter of law. The LPSC accepts this position.[228] All parties seemingly accept the position that this issue is now moot.

640. The undersigned finds this issue has been resolved and is no longer an issue in these proceedings.

8. Interruptible Load Issue

641. **ISSUE:** Should "interruptible load" be included in the data for the variable "DR" in the 2006 Bandwidth calculation?

642. The undersigned finds Entergy properly included interruptible loads in calculating the Bandwidth Formula. The undersigned finds the opinion of Mr.

[227] *Louisiana Public Service Commission v. Entergy Services, Inc.*, 124 FERC ¶ 61,010 (2008); also at nn.147 & 224.

[228] LPSC RB, at 38.

Larkin to be probative in reaching this finding. The testimony of APSC witness Dr. Berry is also very probative on this issue.

643. LPSC, through the testimony of Stephan Baron alleges that Entergy should not have included interruptible loads in making its calculations pursuant to the Bandwidth formula. Essentially, he argues that for purposes of calculating each Operating Company's 12 CP, interruptible loads should be removed. That removal would necessarily change the Bandwidth allocations of fixed production costs among the Operating Companies.

644. Mr. Larkin opines Entergy appropriately included interruptible loads. He cites previous FERC decisions to support his opinion.[229] Dr. Berry was also of the opinion that the Commission had already firmly decided this issue contrary to Mr. Baron's position.

645. LPSC presented no new or additional evidence or reasoning to exclude the interruptible loads and the undersigned takes administrative notice of the previous aforementioned decision of the Commission and adopts the testimony of both Mr. Larkin and Dr. Berry on this issue. Moreover, in its Reply Brief, LPSC has recently conceded this issue.[230]

VII. CONCLUSION AND FINDINGS OF FACT

A. Conclusion

646. The undersigned finds Service Schedule MSS-3 is the proper methodology to calculate the Bandwidth formula. The undersigned finds ETR-26 and ETR-28 may continue to be applicable when the Service Schedule MSS-3 does not address a subject, in accordance with previous directives of the Commission.

647. The undersigned further finds that the totality of the evidence establishes that Entergy was not imprudent by not exercising the right of first refusal for Entergy Arkansas to acquire the ISES 2 capacity in 1996 and 1997. Entergy had other reasonable alternatives which appeared to be more cost effective at the time.

648. Moreover, the market conditions at the time warranted a more cautious approach to acquiring large scale generating capacity. Entergy had reasonable belief at the time that due to other factors such as ROA and co-generation, it

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[229] *Louisiana Public Service Commission v. Entergy, Inc.*, 119 FERC ¶ 61,212 (2007).

[230] LPSC RB, at 38.

would likely lose load and industrial customers.

649. The undersigned finds that Entergy's allocation of a pro rata portion of Entergy Arkansas' Bandwidth payments to Ameren, based upon purchased energy related costs which are passed through its contract with Ameren, is just and reasonable, and sufficiently covered by the terms and intent of the Ameren service agreement.

650. Entergy erroneously calculated nuclear depreciation and de-commissioning expenses for purposes of determining the Bandwidth payments. Entergy must recalculate the Bandwidth payments using depreciation expenses consistent with the nuclear license durational life as granted by the NRC.

651. The undersigned further finds that Entergy properly calculated the net area load variable. The methodology used was in substantial compliance with the directives of the Commission to use ETR-26 and ETR-28, as explained by Mr. Louiselle in his testimony. ETR-26 and ETR-28 was used to the extent it could be, without causing obvious "synchronization" errors.

652. More importantly, the undersigned agrees with Entergy and the FERC Staff that certain amendments to the tariff through Service Schedule MSS-3 are legally sufficient and provide the appropriate methodology used by Entergy. The undersigned finds the Commission intended to achieve rough production cost equalization. The LPSC position if adopted would result in substantially erroneous calculations.

653. The undersigned finds with some corrections, that Entergy utilized proper accounting practices. These corrections include the proposed corrections to Account 923 and River Bend A&G as advocated by Mr. Louiselle, are accepted as the appropriate remedies. Entergy should also re-calculate and exclude any costs in Account 924 which is not related to production, pursuant to the recommendation from the MPSC.

654. The undersigned further finds the Ameren contract issue has no impact upon the ETEC contract.

655. The errors contained in calculating nuclear depreciation expenses result in an unjust and unreasonable rate filing. The Bandwidth formula should be corrected and recalculated in accordance with this decision and the recommendations of the FERC Staff.

656. Furthermore, the undersigned agrees with the position of the LPSC that this re-calculation should be done immediately and that if a depreciation study is

deemed necessary, it be done prospectively.

B. Adopted Findings of Fact

657. In 2006, the Entergy System consisted of five Operating Companies that are planned and operated as a single, integrated electric system under the terms of the Entergy System Agreement (System Agreement). The "Operating Companies," as they existed in 2006 are: Entergy Arkansas, Entergy Gulf States, Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans. The generating resources and bulk transmission facilities of the Operating Companies are referred to collectively as the "Entergy System" or "System."[231]

658. The System Agreement, including seven attached service schedules, is the FERC- approved tariff that provides the basis for the operation and planning of the electric generation and transmission facilities of the Entergy System, including the facilities of the five operating companies. The System Agreement governs the wholesale-power transactions among the Operating Companies by providing for joint operation and establishing the basis for allocation among the Operating Companies of the costs associated with the construction ownership and operation of the Entergy System facilities.[232]

659. The System Agreement establishes an Operating Committee that is charged with the responsibility for, among other things, determining generation addition or acquisition plans that provide capacity to meet System load projections and provide service to customers.[233]

660. System resources, including purchased power, are either scheduled or dispatched for the System as a whole to obtain the lowest reasonable cost of energy consistent with reliability requirements.[234]

661. The System Agreement's service schedules prescribe cost allocation principles which are embodied in accounting protocols used to bill the costs of operating the System to the individual Operating Companies and are intended to be implemented in a manner consistent with the System Agreement and the service schedules. This protocol is implemented pursuant to the ISB to each

[231] Entergy IB at App. A.

[232] *Id.*

[233] *Id.*

[234] *Id*. at 2.

Operating Company on a monthly basis. The ISB properly implements the formula rates in the service schedules.[235]

662. Service Schedule MSS-3 is the applicable Commission-approved tariff, and the Bandwidth filing must comply with this service schedule. The Bandwidth formula contained in Service Schedule MSS-3 is consistent with Exhibits ETR-26 and ETR-28, documents prepared by Mr. Louiselle and which had previously been directed by the Commission for use. Exhibits ETR-26 and ETR-2 remain applicable to the extent implementation details are not included in Service Schedule MSS-3.[236]

663. Entergy properly calculated net area load requirements by using Form 1 data, in accordance with Service Schedule MSS-3. By doing this, it avoided creating a synchronization error in the Bandwidth calculation, which would have caused substantial errors in allocating Bandwidth payment calculations. Although Exhibits ETR-26 and ETR-28 used ISB data in their calculations of the net area load, the formula in Exhibit ETR-28 did not specify the source of the data to be used. Instead, Exhibit ETR-28 merely set out the data used without specifying any source for that data.[237]

664. The use of Form 1 data as the source of data for the variable ER is consistent with the Bandwidth formula contained in Service Schedule MSS-3. It is appropriate to use Form 1 data because such use results in the correct calculation under the Bandwidth formula.[238]

665. The Entergy System purchases power, including economy energy, from third parties instead of running its own facilities when it is economic to do so and is consistent with operational and reliability requirements. Merchant generators, which include Qualified Facilities (QF) and/or independent power producers, constructed an extraordinary amount of generation within the Entergy System from 1999 through 2004.[239]

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[235] *Id.*; FERC Staff RB at 3.

[236] Entergy IB at App. A .

[237] *Id.* at 2-3.

[238] *Id.*

[239] *Id.* at 6-7.

666. The Entergy System modified its Open Access Transmission Tariff to facilitate purchases from merchant generation. The Entergy System engaged in sufficient economic planning studies for the transmission system that evaluate the economics of purchased power, including the decision whether to exercise a right of first refusal pertaining to ISES 2 capacity.[240]

667. The Entergy System manages load obligations that are uncertain and volatile due to circumstances not controlled by the System (*e.g.*, changes in weather, changes in large industrial customer operations, imbalances caused by merchant generators, energy put to Operating Companies by QFs). The need for flexible capability places a limitation on the amount of power than can be purchased from the wholesale market. The Entergy System generally made reasonable use of wholesale market opportunities in light of operating constraints surrounding uncertainty in load, at all relevant times pertinent to this decision.[241]

668. The Entergy System historically has generally purchased power, including economy energy, from third parties instead of running its own facilities when it is economic to do so and is consistent with operational and reliability requirement.[242]

669. The ISES 2 is an 842 MW coal-fired electric generation unit that was placed in service in 1984, and which is operated by EAI. Initially, ISES 2 was jointly owned by a number of entities, including EAI and EMI.[243]

670. In 1990 EAI had an oversupply of capacity, and as a consequence it sold its 265 MW share of ISES 2, along with a 100% share of the gas-fired Ritchie Unit 2, to EPI. This sale was approved by the APSC. One of the conditions of the APSC's approval was that before EPI could sell its ownership of the capacity to a third party, it first was required to offer EAI the opportunity to repurchase the capacity at net book value.[244]

671. In the early to mid 1990s, the region's oversupply position made it difficult for EPI to make sales from the capacity that it had purchased from EAI. As of 1996, EPI had been unable to make long or intermediate term wholesale

[240] *Id.*

[241] *Id.*

[242] *Id.*

[243] *Id.*

[244] *Id.* at 8.

sales from 180 MW of its ISES 2 capacity and had to resort instead to short-term sales. As a result, EPI decided that it would attempt to sell an ownership share of ISES 2 capacity equal to the 164-180 MW of uncommitted capacity that it had been unable to market. In order to do this, however, EPI first was required to offer the ISES 2 capacity to EAI under the same terms as it had been offered by EAI to EPI, *i.e.*, at net book value.[245]

672. EPI offered the 164-180 MW of ISES 2 capacity to EAI at a price of $450/kW, the then-current net book value, for a total price of over $80 million. This offer was evaluated under the direction of Mr. Frank Gallaher, who at the time was Chairman of Entergy's Operating Committee and was the System's principal executive responsible for operations. Mr. Gallaher and his staff knew the costs of ISES 2 because EAI operated the facility, EMI owned a partial interest in the facility, and ESI included ISES 2 in the overall dispatch of System resources.

673. Mr. Gallaher and his staff also had access to detailed information about the expected future generational needs of the System, the various alternative resources that could be considered to meet those future needs, and the expected marginal cost of each of those resources. This information recently had been compiled and analyzed in Entergy's 1995 Integrated Resource Plan (the 1995 IRP), which had been approved by Entergy's Operating Committee (the internal Entergy organization responsible for System-wide resource planning) only a few months before in September 1995.[246]

674. At the time of the offer, based on their knowledge of both the costs of ISES 2 and the projected least cost mix of generation resources for meeting Entergy's load requirements over the next ten years, Mr. Gallaher and his staff determined that it would cost more to acquire and operate ISES 2 than it would to meet Entergy's load requirements using the alternatives identified in the 1995 IRP.[247]

675. In assessing his decision, Mr. Gallaher considered that at the time, impending retail competition and the potential for increased cogeneration, which made it likely that Entergy would lose significant amounts of its retail load, and that such load losses would render an expensive capacity acquisition such as ISES 2 even more uneconomic. In 1996-97, proceedings were underway in all of the Entergy retail jurisdictions to explore implementation of retail competition, which

[245] *Id.*

[246] *Id.*

[247] *Id.*

presented the risk that Entergy would lose significant retail load in the years to come. Additionally, due to the high concentration of industrial load, Mr. Gallagher believed that Entergy's service area was particularly vulnerable to loss of load due to cogeneration.[248]

676. The resource acquisition plan adopted in the 1995 IRP was based on these two factors – the availability of relatively cheap capacity for the next nine – ten years combined with the need to retain flexibility in light of changes in the industry.[249]

677. Based on these considerations, as well as on consultations with his planning staff who also considered the potential costs and benefits, Mr. Gallaher determined that Entergy Arkansas should not exercise its purchase option for the ISES 2 capacity.[250]

678. There is sufficient evidence in the record which supports a decision that the purchase of ISES 2 at the price offered by EPI was higher than the cost of the other alternatives identified in the 1995 IRP.[251]

679. In addition to offering the of ISES 2 capacity to Entergy Arkansas, EPI also attempted to sell the capacity to other parties. Out of the at least 9-10 other parties that were offered the ISES 2 capacity in 1996 in addition to EAI, only one – the City of Jonesboro, Arkansas – purchased any capacity at all. Jonesboro paid the same $450/kW price that EPI had offered the capacity to EAI. Jonesboro purchased only 84 MW of ISES 2 capacity, which is less than half of the 180 MW that EPI had made available for sale. Moreover, as a municipality, Jonesboro had access to special tax free bonds and other financing advantages that were not available to EAI or other investor-owned utilities.[252]

680. A year and a half later, EPI reached agreement with the ETEC to sell additional ISES 2 capacity. As a result, EPI again offered the capacity to Entergy Arkansas. Mr. Gallaher again determined that the capacity would not be beneficial based on essentially the same grounds as in 1996. Subsequently, EPI

[248] *Id*. at 9.

[249] *Id.*

[250] *Id.*

[251] *Id.*

[252] *Id*. at 9-10.

sold some, but not all, of its remaining ISES 2 capacity to ETEC, again an entity with tax-advantaged financing not available to EAI.[253]

681. Under all of the circumstances existing at the time, Entergy was not imprudent in deciding not to exercise its right of first refusal to reacquire for Entergy Arkansas ISES 2 capacity in 1996 and 1997.

682. Under the contract between EAI and Ameren, EAI is entitled to recover its purchased energy costs recorded in Account 555.[254]

683. As ordered by the Commission, the Bandwidth payments are recorded in Account 555, which is entitled Purchased Power. Bandwidth payments encompass purchased power expenses, and are recoverable under the Ameren contract unless established to be payments for capacity instead of energy.[255]

684. In the 2006 Bandwidth calculation, Entergy Arkansas' Bandwidth payments consist of payments related to energy costs, and not capacity-related costs. The Bandwidth Payments charged to Ameren are based upon purchased energy expenses.[256]

685. All Entergy System generation, including purchased power, is dispatched for the System as a whole and then allocated after-the-fact among the Operating Companies and to off-system joint account sales. The after-the-fact allocation of all System energy and associated costs among the Operating Companies and to Joint Account Sales is generally accomplished pursuant to FERC approved Service Schedule MSS-3.[257]

686. After removing the energy and costs associated with off-system sales, Service Schedule MSS-3 first allocates energy from the lowest cost resources committed to System dispatch to the load of the Operating Company making the resource available. Service Schedule MSS-3 next allocates and prices any energy in excess of the load of the owning Operating Company to other Operating Companies as exchange energy to meet their loads. The energy resulting from

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[253] *Id.*

[254] *Id* at 11-12.

[255] *Id.*

[256] *Id.*

[257] *Id.*

System dispatch not needed to meet the loads of the Operating Companies is allocated to serve off-system joint account sales.[258]

687. Service Schedule MSS-3 also includes the calculation of Bandwidth payments. The Bandwidth payments at issue are a reallocation of the energy costs allocated among the Operating Companies and constitute payments for the energy allocated to EAI under Service Schedule MSS-3.[259] ETR 26 and ETR 28 are still applicable to the extent the Service Schedule MSS-3 does not address an item.[260]

688. Staff Witness John K. Sammon, who initially questioned whether the RPCE payments/credits could be considered "Purchased Energy Expenses Charged to Account 555" under the Ameren contract, opined that these costs are nevertheless energy-related.[261]

689. The Ameren contract therefore allows for the pass-through of purchased energy costs allocated to EAI under Service Schedule MSS-3, including the Bandwidth payments at issue.[262]

690. Pursuant to the Ameren contract, EAI is entitled to recover its purchased energy costs recorded in Account 555. The Bandwidth Payments are recorded in Account 555, which is entitled Purchased Power. Therefore, the Bandwidth payments are purchased power expenses, and should be recoverable under the Ameren contract unless they constitute payments for capacity instead of energy. Ameren has not established that the payments were for capacity.[263]

691. The ETEC contract explicitly provides for the pass-through of RPCE payments/credits. Both ETEC and Entergy agree that the intent of the parties in the ETEC contract was to allow the full pass-through of all Service Schedule MSS-3 costs, including RPCE payments. The Ameren contract has no impact and does not control the ETEC contract.[264]

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[258] *Id.*

[259] *Id.*

[260] Staff RB, at 2-3.

[261] ETEC IB at 4.

[262] Entergy IB at 12.

[263] *Id.*

692. FERC precedent requires that the depreciation and decommissioning expenses of a nuclear plant should reflect the license life as established by the NRC.[265] The FERC has recently reaffirmed that position in a proceeding involving the Grand Gulf nuclear unit.

693. The use of depreciation lives that accelerate the recovery of nuclear investment costs in the Bandwidth formula in this filing is unjust and unreasonable. The tariff, as provided in Service Schedule MSS-3 does not require the acceptance of the Retail Regulators' decisions because it provides that the FERC may establish depreciation expenses if it determines it should do so.[266]

694. The FERC has exclusive jurisdiction over the Bandwidth formula. The acceleration of EAI's nuclear depreciation is unjust and discriminatory because it moves artificial depreciation costs into the period in which EAI expects the Bandwidth to exist and artificially lowers depreciation costs thereafter. This action also discriminates against current ratepayers in favor of future generations, and skews the Bandwidth calculations.[267]

695. The nuclear service life policies of the Retail Regulators, which are reflected in the FERC Form 1 data for the various Operating Companies and the Bandwidth calculation, are inconsistent among the various jurisdictions and with Commission policy. The nuclear depreciation and decommissioning-related costs used for the 2006 Bandwidth calculation are not just and reasonable and are also discriminatory and preferential.[268] Service Schedule MSS-3, Sec. 30.12, expressly provides the FERC may set nuclear depreciation and decommissioning expenses, if it so chooses.

696. The net operating loss (NOL) carry back associated with Hurricanes Katrina and Rita reported in Account 165 should not be included in the 2006 Bandwidth calculation.[269]

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[264] ETEC IB at 3-4.

[265] Staff IB at 75.

[266] *Id*.

[267] *Id*.

[268] Staff IB, FF at 7.

[269] *Id*.

697. To avoid including the NOL carry back in the 2006 Bandwidth calculation, it was appropriate either to remove the carry back from Account 165 as part of the Bandwidth calculation or else to record it in Account 143, which is not included in the Bandwidth calculation. Use of Account 143 would have been more appropriate.[270]

698. ESI's accounting for the Hurricanes Katrina and Rita related costs was appropriate.[271]

699. Storm reserve accounting was not used in connection with the interim storm damage recovery authorized by the LPSC because the interim recovery process was not an accrual for storm damage. The FERC USOA definition of Account 924 specifically states that "this account shall include the cost of insurance or reserve accrurals … ." The interim storm damage recovery was not a reserve accrual and therefore use of Account 924 is inappropriate.[272] Entergy should recalculate and exclude any costs in Account 924 which are not related to production.[273]

700. The unique nature of the interim Hurricane storm damage recovery was such that it should not have been recorded in any of the accounts that are reflected in the Bandwidth Calculation for 2006.[274]

701. Section 30.12 of the Bandwidth Formula in Service Schedule MSS-3 provides that certain types of accumulated deferred income tax (ADIT) amounts should be excluded from the Bandwidth Calculation.[275]

702. The exclusion of certain ADIT amounts in the 2006 Bandwidth calculation is consistent with Section 30.12 of the Service Schedule MSS-3.[276]

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[270] Entergy IB at App. A.

[271] *Id.*

[272] *Id.*

[273] Exhibit No. MC-1 at 25.

[274] Entergy IB at App. A.

[275] *Id.*

[276] *Id.*

703. Errors exist pertaining to Account 923. $6.6 million of the approximately $62.4 million in charges to Account 923 in 2006 should be assignable to an account other than Account 923, as previously determined by Entergy.[277]

704. Errors exist pertaining to A&G costs and other taxes associated with the 30% of the River Bend unit that represents the unregulated portion of the unit (often referred to as River Bend 30%). Certain costs were erroneously included in the bus bar production costs of EGS.[278]

705. The River Bend 30% A&G costs should be removed as proposed by Entergy, through a two step process: First, A&G costs for the River Bend 30% should be subtracted from the total A&G costs for EGS (the Company that owns River Bend); and, Second, the Company's residual A&G amount (*i.e.*, the A&G that does not include River Bend 30%) should be functionalized to production using a labor ratio that does not include the River Bend 30% labor. A similar adjustment calculation should be made for the variable “Other Taxes.”[279]

706. The Commission issued an order on July 2, 2008, in Docket No. EL08-51, setting the Spindletop amendment issue (as set forth in Issue 9(b) above) for hearing.[280] The issue is moot for purposes of this proceeding.

707. Spindletop costs are reflected on the books of one Operating Company, EGS. The costs associated with Spindletop include the as-incurred costs due to the LPSC-ordered ratemaking treatment, and costs associated with prior periods. The Bandwidth Formula includes accounts containing the as-incurred costs associated with Spindletop, but not costs associated with prior periods. Similarly, Exhibits ETR-26 and ETR-28 reflected the actual, as-incurred costs of Spindletop, because such costs were recorded in Account 501, an account eligible for inclusion in the Bandwidth formula. ESI's compliance filing (accepted in the November 2006 and April 2007 Orders) continued to reflect these costs associated with Spindletop.[281]

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[277] *Id.*

[278] *Id.*

[279] *Id.*

[280] *Id.*

[281] *Id.*

708. Entergy properly recorded and implemented the accounting issues relating to the Spindletop facility.[282]

709. The issue of the Bandwidth Formula's treatment of the ADIT associated with the capital lease portion of the Waterford 3 nuclear generation unit (the Sale/Leaseback), is now moot. In the Commission's July 2, 2008 Order in Docket No. EL08-51, the Commission granted the LPSC request to amend the Bandwidth Formula to remove the Waterford 3 ADIT Sale/Leaseback amounts, effective March 31, 2008, and all parties accept this as settlement of this issue.[283]

710. The LPSC's argument that interruptible loads should be excluded from the data for the variable "DR" in the Bandwidth Formula, has been rejected by the Commission on two occasions. The LPSC now concedes this and withdrawals its opposition pertaining to this issue.[284]

ORDER

WHEREFORE IT IS ORDERED, that subject to review by the Commission on appeal or on its own motion, Entergy, consistent with the findings and conclusions of this Initial Decision, shall make the ordered changes in formulating the Bandwidth calculations and collect the rates authorized by this decision, subject to the findings and conclusions set forth herein.

Michael J. Cianci, Jr.
Presiding Administrative Law Judge

[282] *Id.*

[283] *Id.*

[284] *Id.*

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