UNITED STATES OF AMERICA 106 FERC ¶ 63, 012
FEDERAL ENERGY REGULATORY COMMISSION

Louisiana Public Service Commission

v. **Docket No. EL01-88-001**

Entergy Services, Inc., et al.

INITIAL DECISION

(Issued February 6, 2004)

Appearances

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Mary W. Cochran, Esq., Randolph Hightower, Esq. and Ted Thomas, Esq. on behalf of Arkansas Public Service Commission

George M. Fleming, Esq. and Patricia L. Trantham, Esq. on behalf of Mississippi Public Service Commission

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Larry F. Eisenstat, Esq., Michael R. Engleman, Esq. and Christopher C. O'Hara, Esq. on behalf of TECO Power Services Corporation

Mitchell F. Hertz, Esq., Gerald F. Masoudi, Esq. and Jeffrey J. Williamson, Esq. on behalf of Arkansas Electric Energy Consumers, Inc.

William J. Collins, Esq. and Edith A. Gilmore, Esq. on behalf of Federal Energy Regulatory Commission Trial Staff

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Derek A. Dyson, Esq. and Thomas L. Rudebusch, Esq. on behalf of Louisiana Generating, LLC

R. Wilson Montjoy, II, Esq. on behalf of Mississippi Manufacturers Association

Roger St. Vincent, Esq. on behalf of Occidental Chemical Corporation

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Lawrence Brenner, Presiding Administrative Law Judge

I. INTRODUCTION AND BACKGROUND[1]

1. The case at bar commenced on June 14, 2001 when the Louisiana Public Service Commission (LPSC), along with the Council of the City of New Orleans (CNO) filed a complaint against Entergy Corporation, Entergy Services, Inc. (ESI), Entergy Arkansas, Inc. (EAI), Entergy Louisiana, Inc. (ELI), Entergy Mississippi, Inc. (EMI), Entergy New Orleans, Inc. (ENOI), Entergy Gulf States, Inc. (EGSI), and System Energy Resources, Inc. (SERI) (collectively as Entergy). The complaint deals with the Entergy System Agreement, a FERC[2] rate schedule that allocates certain costs among the Entergy

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[1] Unless it is clear from the context, citations to post-hearing initial briefs (IB), reply briefs (RB), and exhibits are prefaced by the abbreviation for the submitting party: Entergy Corporation (ETR), Louisiana Public Service Commission (LC), Council of the City of New Orleans (CNO), Arkansas Public Service Commission (AC), Mississippi Public Service Commission (MPS) (and collectively A&MC for their joint briefs), Arkansas Electric Energy Consumers, Inc. (AEE), TECO Power Services (TPS), or Staff (S). Citations to the transcript are noted by the abbreviation "Tr." followed by the page number(s). Unless it is apparent, I identify the witness or the nature of the exhibit in a parenthetical after an exhibit or transcript citation. Furthermore, with the exception of LC-7C (which has a confidential version listed as LC-7C-C), all exhibits containing a "C" suffix are confidential. Any references in the initial decision to a "C" suffix exhibit do not reveal any information marked as "confidential" by the sponsoring party.

[2] I refer to the Federal Energy Regulatory Commission as the Commission or FERC, and to the FERC Trial Staff, which is an active party in this case, as Staff.

Operating Companies in several jurisdictions. LPSC, now the sole complainant,[3] presents four sets of issues. The first is whether the cost allocations among the Operating Companies in the Entergy System Agreement have become unjust, unreasonable and unduly discriminatory in violation of Sections 205 and 206 of the Federal Power Act (FPA). If so, then the second issue is whether the Entergy System Agreement should be altered to fully equalize or more closely align the production costs of the Entergy Operating Companies. The third set of issues involves whether certain costs should be adjusted when comparing the production costs among the Operating Companies. Finally, the fourth issue is whether System Service Agreement Schedules MSS-1 and MSS-3 should be modified as an alternative remedy. Notice of the Complaint was issued by the Commission on June 15, 2001. On February 13, 2002, the Commission set the Complaint for investigation and hearing. 98 FERC ¶ 61,135.

2. Entergy Corporation is a public utility holding company that provides electric service at retail through five operating companies – EAI, ELI, EMI, EGSI and ENOI. The Entergy Operating Companies are respectively regulated by the Arkansas Public Service Commission (APSC), the LPSC, the Mississippi Public Service Commission (MPSC), the Public Utility Commission of Texas (PUCT) and the LPSC, and the CNO. ESI provides operating services to the five operating companies, and acts as the agent for the parent corporation in the Entergy System Agreement. SERI is a generating subsidiary of Entergy that owns a 90 percent interest in the Grand Gulf I Nuclear Generating Facility (Grand Gulf). Under the terms of the Unit Power Sales Agreement (UPSA), SERI sells 90 percent of the capacity of the plant in fixed percentages to the four operating companies that are participants in the agreement, namely EAI, EMI, ELI and ENOI.[4]

3. The Entergy System has operated for over fifty years under a System Agreement which acts as an interconnection and pooling agreement, provides for the joint planning, construction and operation of the Operating Companies' facilities, and maintains a coordinated power pool among the five companies. Three System Agreements have been filed by Entergy going back to 1951. The current System Agreement was filed in 1982.

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[3] The CNO withdrew as a complainant and became an intervenor as the result of a settlement between Entergy and the CNO. *See* Notice of the Council of the City of New Orleans' Withdrawal as a Complainant and Motion to Remain a Party with Intervenor Status (June 6, 2003).

[4] EGSI, which is not a participant in the Grand Gulf UPSA, did not become an Entergy Operating Company until the former Gulf States Utilities Co. merged with Entergy in 1993. *See Entergy Corp. and Gulf States Utilities Co.*, 65 FERC ¶ 61,332 (1993).

4. There are seven schedules in the System Agreement,[5] only two of which are relevant in this proceeding. Service Schedule MSS-1 equalizes reserve capacity among the Operating Companies by requiring that the "short" companies make payments to the "long" companies under a formula based on the "long" companies' prior year's cost of gas and oil-fired steam generation. Service Schedule MSS-3 allocates energy each hour among the Entergy Operating Companies on an after-the-fact basis in a manner that each Operating Company that generates power in excess of its needs is deemed to sell that energy into the System Exchange for the use of the other Operating Companies in the Entergy System. Furthermore, it is presumed that the selling company places its most expensive energy into the Exchange and keeps its cheapest energy in order to meet its own base load requirements.

5. The 1982 System Agreement and the UPSA allocations of the Grand Gulf generation capacity were the subjects of litigation both in front of the Commission and the D.C. Circuit. In two cases brought by Entergy, then known as Middle South Utilities (MSU),[6] it sought to allocate power from Grand Gulf among the then four Operating Companies, and amend the System Agreement to reflect this change. In the first case, Administrative Law Judge Ernst Liebman examined the UPSA filed to allocate energy and costs of the construction of Grand Gulf. *Middle South Energy, Inc*., 26 FERC ¶ 63,044 (1984). Finding that since the then-MSU System was centrally controlled and directed, Judge Liebman ordered that the Grand Gulf capacity costs should be allocated equally among the then-existing Operating Companies in the Middle South System in proportion to each of their share of System demand. *Id.* at 65,109. In the second case, Administrative Law Judge Daniel Head reviewed LPSC's proposal to amend the System Agreement to equalize the production costs among the companies. *Middle South Services, Inc.*, 30 FERC ¶ 63,030 (1985). Judge Head determined that Grand Gulf was indeed planned for the System and its costs should be distributed equally, but rejected the proposal to equalize costs among the Operating Companies. *Id.* at 65,168-70.

6. In Opinion No. 234, the Commission jointly reviewed the initial decisions of Judges Liebman and Head. *Middle South Energy, Inc.*, Opinion No. 234, 31 FERC ¶

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[5] The seven Service Schedules in the System Agreement are as follows: MSS-1 (Reserve Equalization); MSS-2 (Transmission Equalization); MSS-3 (Exchange of Electric Energy Among the Companies); MSS-4 (Unit Power Purchase); MSS-5 (Distribution of Revenue from Sales Made for the Joint Account of all Companies); MSS-6 (Distribution of Operating Expenses of System Operations Center); and MSS-7 (Merger Fuel Protection Procedure).

[6] Note that the convention adopted in this decision is to refer to the Operating Companies by their present names unless otherwise explicitly stated (ex. Entergy over Middle South Utilities, ELI over LP&L, etc.).

61,305 (1985). FERC took issue with Judge Head's finding that Grand Gulf was the only plant that was planned for the system as a whole, stating that the system showed a considerable level of centralization in planning for system resources. *Id.* at 61,650. It determined that the combination of the revised System Agreement with the Grand Gulf allocations that it was requiring (which had the effect of allocating the investment costs for all of the Entergy nuclear units among the Operating Companies in proportion to their demands) would produce just and reasonable results, thereby making full equalization unnecessary. *Id.* at 61,654-56. On rehearing, the Commission reaffirmed its ruling, adding that it did not regard the system as a monolithic entity, but rather a closely integrated system where the Operating Companies were each intimately involved with the planning process, leaving final decisions up to the then-MSU Operating Committee. *Middle South Energy, Inc.*, Opinion No. 234-A, 32 FERC ¶ 61,425, 61,952-53 (1985).

7. The decision of the Commission was appealed by several parties to the United States Court of Appeals for the District of Columbia Circuit. *Mississippi Industries v. FERC*, 808 F.2d 1525 (D.C. Cir. 1987), *vacated in part*, 822 F.2d 1104 (D.C. Cir. 1987) (per curiam), *cert. denied*, 484 U.S. 985 (1987). The D.C. Circuit upheld the Commission's finding that full equalization of production costs was not needed because rough equalization of production costs existed. 808 F.2d at 1565. However, on rehearing, the D.C. Circuit vacated the portion of the decision that approved FERC's allocation of Grand Gulf and remanded the case to the Commission for reconsideration of the decision to equalize the capacity costs of all nuclear plants, an explanation of the criteria used to determine what constitutes "undue discrimination," and an explanation as to why the Commission's decision in the case was not unduly discriminatory. *Mississippi Industries v. FERC*, 822 F.2d 1104, 1105 (D.C. Cir. 1987).

8. On remand, FERC examined the definition of undue discrimination in light of the standards discussed in the Federal Power Act, and determined that principles of fairness mandated that since generation capacity was built in response to demand, distribution of the costs of that capacity should also be made in proportion to demand. *System Energy Resources, Inc.*, Opinion No. 292, 41 FERC ¶ 61,238, 61,616 (1987). The request for rehearing was denied by the Commission in Order 292-A. *System Energy Resources, Inc.*, Opinion No. 292-A, 42 FERC ¶ 61,091 (1988). On appeal to the D.C. Circuit, the Court stated that FERC's allocation of system capacity costs in proportion to system demand was correct, as it reflected a reasoned judgment. *City of New Orleans v. FERC*, 875 F.2d 903, 905 (D.C. Cir. 1989).

9. The Commission later dismissed a complaint filed by the LPSC questioning whether the System Agreement should be revised to remove curtailable load from the calculation of peak load responsibility. *Louisiana Public Service Commission v. Entergy Services, Inc.*, 76 FERC ¶ 61,168 (1996), *reh'g denied*, 80 FERC ¶ 61,282 (1997). The D.C. Circuit remanded that case to FERC for rehearing on the rough production cost equalization standard. *Louisiana Public Service Commission v. FERC*, 184 F.3d 892,

899 (D.C. Cir. 1999). On remand, the Commission consolidated that case with another previously filed complaint already scheduled for a hearing on retail competition to determine whether Entergy's System Agreement should be revised. *Louisiana Public Service Commission v. Entergy Services, Inc.*, 93 FERC ¶ 61,013 (2000). During the course of that hearing, the Presiding Administrative Law Judge decided to certify questions to the Commission as to whether the record should be reopened to determine whether Entergy's Operating Companies were in rough equalization. The Commission remitted the rough production cost equalization issue for a hearing. *Louisiana Public Service Commission and the Council of the City of New Orleans v. Entergy Services, Inc.*, 95 FERC ¶ 61,266 (2001). The parties subsequently agreed that the question of rough equalization should be heard in a separate proceeding, to be commenced by the LPSC and CNO. *See* Certification of Uncontested Partial Settlement, 96 FERC ¶ 63,001, 65,002 n.14 (2001).

10. After the LPSC and CNO filed a Complaint on June 14, 2001, the Commission filed an "Order on Complaint and Establishing Hearing and Settlement Judge Procedures" on February 13, 2002. *Louisiana Public Service Commission v. Entergy Corp.*, 98 FERC ¶ 61,135 (2002). The hearing was to be held in abeyance pending action by the Settlement Judge. Settlement efforts failed, and on March 13, 2002, the Chief Administrative Law Judge terminated settlement proceedings and appointed Jacob Leventhal as Presiding Judge.

11. On August 26, 2002, due to the retirement of Judge Leventhal, the Chief Judge issued a Substitute Designation of Presiding Administrative Law Judge, appointing me as Presiding Judge. The hearing began on July 7, 2003 and concluded on August 22, 2003. The evidentiary record consists of 6,218 pages of hearing transcripts and over 390 exhibits submitted by the parties in pre-filed testimony and during the hearing.

12. Timely initial and reply briefs have been filed and duly considered. The omission from this decision of any argument or portion of the record raised by the parties in their briefs does not mean that it has not been considered. Rather, it has been evaluated and found either to lack merit or significance or to tend only to lengthen this decision without altering its substance or effect. Any pending motions not ruled upon during the hearing or in this decision are deemed denied.

II. ROUGH PRODUCTION COST EQUALIZATION

A. Precedent Regarding Production Cost Equalization Among the Entergy Operating Companies:

13. As noted briefly in the Introduction to this decision, the Commission and the courts have been considering the issue of the comparative production costs among the Entergy Operating Companies under the current 1982 System Agreement for at least a generation, since the FERC administrative litigation leading to the decisions by Judges

Head and Liebman that were considered initially on appeal in 1985 in Commission Opinion No. 234. Thus, there are a series of decisions with important teachings. The parties in the instant case also participated in the earlier cases and are of course very familiar with them. However, in support of their disparate positions, the parties at times are selective in their recognition of what the earlier rulings mean for the latest controversy in the current timeframe. Others not blessed, or burdened, with that past involvement might benefit from the context of the precedent. For these reasons, I believe it will be helpful to set forth at some length a summary of the relevant precedent regarding production cost equalization among the Entergy Operating Companies.

14. In *Mississippi Industries v. FERC*, the D.C. Circuit reviewed the decision of the Commission, as embodied in Opinion Nos. 234 and 234-A. 808 F.2d.1525 (D.C. Cir. 1987). In examining the historical operation of the System Agreements on the then-MSU System, 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 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.

Id. at 1530 (citations omitted). Because of the unexpected rise in the cost of constructing the nuclear 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*." *Id.* at 1532 (emphasis in original).

15. 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." *Id.* at 1540. 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." *Id.* at 1541. Examining the 1982 System Agreement, the Court wrote the following:

> Under the 1982 System Agreement, capacity and energy costs are allocated separately. As for energy, each company is entitled to first call on the lowest cost energy generated by the plants located within its service area (and by Grand Gulf up to its UPSA percentage entitlement). The energy generated by a company's plants in excess of that company's demand goes into a pool of energy available to companies whose plants produce less energy than they demand. Such companies may purchase the lowest cost energy available in the pool.
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> The 1982 System Agreement also establishes a formula to equalize roughly the costs of *capacity* to generate energy. This is achieved by equalizing capacity among the operating companies with corresponding capacity equalization payments. Companies that are "long" on capacity -- *i.e.*, those whose percentage of total System demand -- contribute their excess capacity to "short" companies -- *i.e.*, companies whose percentage of total System capacity is less than their percentage of total System demand. In return, the "short" companies make capacity equalization payments to the "long" companies.
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> . . .
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> The operating companies intended to roughly equalize the System's capacity costs among themselves by executing the UPSA and the 1982 System Agreement. And, indeed, *at the time they were negotiated,* these agreements appeared to achieve that objective. . . . The cost of nuclear capacity was assumed to be roughly equivalent. Thus, each company would share in the cost of the older oil and gas capacity -- either by having constructed it or by making capacity equalization payments -- and each company would share in the cost of the System's newer capacity -- by constructing nuclear and/or coal fired units.

Id. at 1554-55 (emphasis in original). The Court recognized that "Judge Liebman concluded that the facts were insufficient to outweigh 'the profound undue discrimination caused by [the UPSA] allocation.'" *Id.* at 1555.

16. 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." *Id*. at 1565. 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 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.

Id. (citations omitted) (emphasis in original).

17. 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.

Id. The Court further stated that "Judge Head concluded that 'production cost pooling and equalization constitutes a drastic deviation from past practices on the system relating to intercompany transactions and would change the underlying nature of such transactions.'" *Id.* (citation omitted).

18. 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." *Id*. at 1566 (emphasis in original). Furthermore, the Court stated that "[h]aving found that 'it is the large cost escalations of Grand Gulf and Waterford 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." *Id*. The Court

further opined that "[p]roduction cost equalization would go much further and eliminate virtually all production and capacity cost disparities among the companies. Though we do not say that the Commission could not have ordered production cost equalization on this record, we think that the Commission correctly concluded that it was not necessary to remedy the undue discrimination found on the System." *Id*.

19. The DC Circuit concluded its opinion with a section affirming FERC's rejection of ALJ Head's allocation of investment costs associated with Grand Gulf. Judge Bork wrote an opinion concurring in part and dissenting in part with the majority. Initially, the petitions for rehearing of the City of New Orleans, Mississippi Industries, the Mississippi Attorney General, the Mississippi Public Service Commission, and Mississippi Power and Light Company were denied on April 3, 1987. *Mississippi Industries v. FERC*, 814 F.2d 773 (D.C. Cir 1987). However, upon reconsideration, the Court vacated the 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. *Mississippi Industries v. FERC*, 822 F.2d 1104 (D.C. Cir 1987).

20. In Opinion No. 292, the Commission responded to the Court of Appeals' remand to explain the criteria for "undue discrimination." *System Energy Resources, Inc.*, 41 FERC ¶ 61,238 (1987). 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." *Id*. at 61,612 n.3 (emphasis in original). Looking at production costs, the Commission found as follows:

> Application of the FPA's prohibition against undue discrimination to the circumstances of this case requires that total production costs, which include both capacity-related costs and energy-related costs, on the entire System be allocated fairly among the members of the MSU Pool. Therefore, in Opinion No. 234, our ultimate concern lay with production costs and the allocation of those costs among the MSU pool members.
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> The record in Opinion No. 234 established that production costs among the MSU System's non-nuclear units were roughly equivalent. Furthermore, the record established that the cost of fuel, which accounts for the majority of energy-related costs, was approximately the same for each of the nuclear plants. Thus, Opinion No. 234 focused on the

> disparities in installed nuclear investment costs which existed on the MSU System.

Id. at 61,615.

21. 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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> 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 the [sic] 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.

Id. at 61,617 (citations omitted).

22. 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.'" *Id*. at 61,618 (citing Colorado Interstate Gas Co. v. FPC, 324 U.S. 581, 589 (1945)). 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 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.

Id. at 61,619-20. Therefore, the Commission found it "unnecessary to adopt a more comprehensive form of cost equalization" for the MSU System. *Id*.

23. In Opinion No. 292-A, the Commission considered the request of the Arkansas-Missouri Parties and the City of New Orleans for rehearing of the Commission's decision in Opinion No. 292. *System Energy Resources, Inc.*, 42 FERC ¶ 61,091 (1988). 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.

Id. at 61,425.

24. On appeal from the final decision of the Commission in Opinion No. 292-A, the D.C. Circuit affirmed the Commission's decision. *City of New Orleans v. FERC*, 875 F.2d 903 (D.C. Cir. 1989). Finding that the Commission had properly explained the criteria for when undue discrimination exists, the Court wrote the following:

> The Commission also explained that its criteria for determining when undue discrimination exists "were that each operating utility should contribute investments to meet the the [sic] 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." This reflects reasoned judgment, because "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."

Id. at 905 (citations omitted).

B. The Entergy System Is Not in Rough Production Cost Equalization

25. As summarized above, the views of the Commission and the courts were that the equalization of nuclear investment costs commencing with the 1986 first year of Grand Gulf operation would lead to rough production cost equalization, because they believed all other production costs were roughly equal among the Operating Companies. However, that is not the case today or for the future. Beginning with 2000, the increase in natural gas prices and the dependence of ELI on gas-fueled generation has caused its production costs to rise dramatically in relation to System average. LC-1 at 36 (Baron); ETR-25 (Louiselle Historical Cost Table). In 2000, ELI was 12% above System average, while EAI was 17% below System average. ETR-25 at 2.[7] Below are the data for 2001-

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[7] Where material, unless noted otherwise, I use the data consistent with the assumptions I find later in this decision to be proper, *e.g.* Vidalia at full contract price, no

2005, using, *arguendo*, the Strategic Supply Resource Plan (SSRP) case most favorable to Entergy for the projected data of 2003 and beyond (but with Vidalia at full price). The high gas projected case, more plausible at least for 2003 and 2004, would result in greater disparity below System average for EAI, and at least the same disparity above System average for ELI. *See* ALJ-3 at 1, 2, 9-11 (prepared by LPSC witness Schnitzer at my request):

PRODUCTION COST DISPARITIES

2001 to 2005 Period

Percent Deviation from System Average

SSRP case and Vidalia at full contract

	EAI	ELI	EMI	ENOI	EGSI	Source
2001	-14	10	-5	26	0	ALJ-1 at 7
2002	-15	11	-3	12	0	ALJ-1 at 8
2003	-14	12	-8	1	3	ALJ-3 at 9
2004	-13	11	-5	9	-1	ALJ-3 at 10
2005	-10	9	-2	3	-1	ALJ-3 at 11
Five-Year Average	-13.2	10.6	-4.6	10.2	0.2	
2001-2005 Average (Rounded)	-13	11	-5	11	0	ALJ-3 at 2

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adjustment for Texaco settlement proceeds to ELI, etc. The data in this decision have been adjusted for load factor by Entergy. No party disagrees that costs should be adjusted for load factor, but the LPSC would allocate fixed nuclear costs differently than Entergy. I find against the LPSC in a later section of this decision. However, that dispute would not produce significantly different percentage deviations given their two methodologies. *See* Tr. 5607, 5618 (Louiselle, comparing Entergy's adjustment to no adjustment). I note additionally that I do not focus on the data for ENOI, which was dramatically above System average in 2000-2002. The CNO has settled its dispute with Entergy over ENOI's disparity as a result of remedial action taken by Entergy to shift lower cost resources to ENOI beginning in 2003.

If the year 2000 is averaged in with the above, the result for EAI is -14%, with ELI remaining at +11%. ALJ-3 at 1.

26. Thus 2000, or even 2000-2003, cannot be chalked off as an aberrational temporary period. There is some reduction projected in the disparity in 2005, but still a huge 19% spread between EAI and ELI. And with gas prices still high during the hearing in 2003, Entergy's high gas case projected the following deviations from System average (ALJ-3 at 9-11):

2003: EAI at -23% to ELI's +12%
2004: EAI at –19% to ELI's +12%
2005: EAI at –14% to ELI's +10%

27. The most recent actual data in the record is through August 2002, and the data labeled 2002 is actually for the 12 month period ending August 31, 2002. *See e.g.* ETR-25 at 2 n.1 (Louiselle Table). Entergy's own projections show the continuation of large disparities beyond 2005. Moreover, as discussed in the SSRP section below in this decision, those projections assume both the timely and effective implementation of Entergy's remedial resource plan – assumptions that are subject to much uncertainty. *See* ETR-107C for the projections through 2010 for the SSRP base case but with Vidalia at full contract price. Entergy's 2003-2010 projected average for its high gas case, with Vidalia at full contract price, is EAI at -15% and ELI at +9%. *See* ETR IB at 10 n.9, 11 and Attachment 1 (citing the record bases for the data).[8] While there is a general trend closer to System average for the first few years from -23% for EAI in 2003 to -12% in 2006, EAI's deviation plateaus at -12% for the remainder of the projected period. Likewise, ELI trends generally toward the System average for the first few years going from +12% in 2003 to +8% in 2006, but then plateaus at +7% for the remainder of the projected period to 2010. *Id.* at Attachment 1, p. 2. Again, these Entergy projections assume the successful implementation of its SSRP.

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[8] The projections for ELI's disparities above System average are conservatively low because they assume a low output for Vidalia of 588 Gwh/year based on the average of two abnormally low years. ELI's production costs will be somewhat higher assuming the average output based on all years of operation of a little over 800 Gwh/year. LC-137 (showing ELI purchases in MWh from Vidalia for 1993-2002); ETR-114 at 2 (demonstrating impact of Vidalia on ELI production costs); Tr. 4629-32 (Turner).

28. According to Entergy witness Schnitzer, each percentage point is worth $11.8 million to ELI. Tr. 5735-39. In the context of possible adjustments to the SSRP, LPSC witness Harlan calculates that for each 1% movement of ELI closer to System average in 2003-2006, it is necessary to reduce ELI's production costs by approximately $15 million. ETR-115C; *See* ETR IB at Attachment 2. LPSC witness Baron testified that a deviation of 5% above System average for ELI would be roughly $77 million. Tr. 1238. Presumably this works out to $15.4 million for each percentage point. Mr. Baron pegged the difference in absolute dollars if ELI were at +5% and EAI were at –5% as approximately $130 million for this 10% bandwidth. *Id.*; LC-1 at 28. Thus, the percentage disparities represent substantial monetary disparities among some of the Operating Companies.

29. I use percentage comparisons for cost disparities because this is the best way to make the comparisons over time. In an objection that I am at a loss to understand, the APSC and MPSC argue that focusing solely on a percentage bandwidth *over time* (their emphasis) leads to illogical results. A&MC IB at 26. To the contrary, their own example of declining costs so that the same cost differential would be a larger percentage of System average precisely is one example of when a percentage comparison is a meaningful one to make. *Id.* at 27-28. I agree with the Staff's view that percentage cost disparities provide a better measure of rough equalization than absolute dollar differences or cents per kWh differences. Percentage differences show the relative effects of production costs. Absolute differences, whether in dollars or per kWh can be misleading since their significance changes as overall production costs increase or decrease. For example, a disparity of $10,000 from a $100,000 total is much more significant than a $10,000 disparity from a total of $1 million. S IB at 11.

30. Entergy, the APSC and MPSC, and the AEE argue that viewed through the lens of the historical period of at least back to 1986, and then with the projections to 2010 averaged in with all those years, the Entergy System is in rough equalization. 1986 is the first year in which the data reflect the Commission's reallocation of Grand Gulf to try to achieve rough production cost equalization. The average of the 17 years of 1986-2002 yields relatively minor deviations from System average of EAI at -1.02%, ELI at -0.20%, EMI at +2.46%, ENOI at +4.32% and EGSI (from 1994 when it merged with Entergy) at -0.48%. And, not surprisingly, when the projected eight years of 2003-2010 are averaged in with all of those 17 historical years the difference is small over the now 25-year cumulative average: EAI at -1%, ELI at -1%, EMI at +3%, ENOI at +3% and EGSI (1994-2010) at 0%. ETR-41 at 21 (Schnitzer - Per Books, Adjusted for Load Factor).

31. I believe it is appropriate to take account of the past record of disparities. However, it is not an accurate reflection of current and future disparities to do so as a past 17 year mathematical cumulative average, which then is used to subsume the present and future years through 2010 in a total 25-year cumulative average. The facts at hand show

that this approach would turn the rationale and goal of the System Agreement precedent on its head.

32. The past 17 years (1986-2002) of load-adjusted data reveal years of ELI and EAI each being above and below System average. They were fairly close to System average for many of the years before 2000. ETR-25 at 2. Until the post-1999 current large divergent trend discussed above, only one of the post-1990 years shows a double-digit deviation; EMI was +16.3% in 1998, but this was one outlying year for EMI, bracketed by years of –6.75% and –2.1%. During that 1991-1999 period, only two other instances occur where an Operating Company exceeds a 7.5% divergence, and then only slightly (ENOI at +8.2% in 1999 and EGSI at –8.05% in 1998). *Id.*

33. There were larger deviations in the 1986-1990 earlier years following the Commission reallocation decision. ELI in that time ranged from about 5.5% to 9.75% below System average, while EAI ranged from 1.75% to almost 11% above System average. EAI's +11% year of 1990 was bracketed by years of +8% and essentially 0%. *Id*. Thus, looking at the history back to 1986, it is clear that prior to the current period beginning with 2000, there was no period where an Operating Company was hammered like ELI has been with double-digit percentage deviations above System average for each of the past four years (2000-2003), while EAI has enjoyed greater than mirror image double-digit disparities below System average. And as detailed above, unless remedied by more than Entergy's plans, this will continue under any of Entergy's own SSRP scenarios for years. ETR IB at 11 and Attachment 1, p. 2; ETR-107C.

34. Despite its own evidence of the many current and future years of great disparity among the Operating Companies, and despite its own lack of plans to meaningfully cure it for at least many more years if at all, Entergy argues that I should cumulatively average 25 years from at least 1986 through projections to 2010. Mathematically, that has Entergy's intended affect of swallowing the large disparities disclosed whether examining each year from 2000-2010, or averaging these years. Predictably, the cumulative averages for the years 1986-2002 showing relatively small disparities are little affected by the addition of data for eight additional years (2003-2010), despite the large disparities currently existing and projected to continue. (There may be some smoothing of the affect because the historic data includes the first three years (2000-2002) that begin the current multi-year period of large disparities.).

35. Entergy supports in part its argument that all the years should be averaged based on some Commission cases that required a party to show that its contract was unreasonable over the "life of the agreement" and not just when a party to a long-term contract sought to change or terminate it. *See e.g. French Broad Electric Membership Corp. v. Carolina Power & Light Co.*, 92 FERC ¶ 61,283 (2000). This makes sense when dealing with arm's-length, independent parties, when one has reaped the benefits of its bargain and then seeks to extricate itself when the benefits may have shifted. But the

cases are not in point when applied to the System Agreement. The "Agreement" here is implemented by the Entergy parent company to regulate the dealings of its controlled affiliate Operating Companies. It is not the result of an open negotiation among independent parties. Moreover, the System Agreement, at least the parts of it material to this proceeding, governs the FERC-jurisdictional tariff and has been relied upon by the Commission, in conjunction with other actions, to achieve rough equalization among the Operating Companies. Thus, it is through the lens of this direct history of this System Agreement that I consider the LPSC's complaint. Although the APSC and MPSC advocate consideration of the disparities over time, with which I agree to the extent I am describing, APSC witness Dr. Berry testified he would not average the past with current costs and does not rely on the "life of the contract" theory. Tr. 3429-37, 3472-74, 3476.

36. As is clear from the summary of the precedent set forth above, the Commission intended to achieve rough production cost equalization. It thought this would be achieved "over time" because it thought the System Agreement would do that once the large nuclear costs were equalized. It recognized that costs grossly disparate from the proper responsibility ratio allocation (i.e. the benefit received by each Operating Company) meant discrimination because Entergy (then-MSU) is a highly integrated company that centrally dispatches its resources to serve the System-wide-loads. That is still true today, as verified by Entergy witnesses. Tr. 4097-98 (Gallaher); Tr. 4808-09 (Harlan). *See also* Tr. 3371 (APSC witness Berry).

37. However, now there is no assurance that rough production cost equalization will be maintained by the System Agreement even with the Commission's 1985 equalization of nuclear investment. As recognized in the summarized precedent, the agreement roughly equalizes excess production costs, not all production costs. Rough production cost equalization generally could be maintained from 1986-1999, with variations from year-to-year but as we have seen without any long-term large bias for one company or another. In the past, prior to the 1985 Commission decision, as the summarized precedent states, this was due to rotation of generating units as they were located in the various Operating Company jurisdictions. 26 FERC at 65,100-01 (Judge Liebman's Decision). There have been few new units since then, and no large base load ones, and now the large increase in natural gas since 2000 has dramatically had a disproportionate affect on ELI's relatively large amount of gas-fired generation, as compared to EAI's relatively large amount of cheaper coal base load capacity. LC-1 at 36 (Baron); Tr. 4144-45, 4149 (Gallaher). The decisions on where, when and what types of units to locate were centrally made by the parent company for the benefit of the entire system. So, while there may be different costs for each Operating Company, on a central System basis differences in cost allocations (relative to load share responsibility) among the Operating Companies are not supported by cost-causation factors. *See System Energy Resources*, Opinion No. 292, 41 FERC at 61,614-17.

38. Applied to the fact of approximately ten years of large cost disparities currently (since 2000) and into the future, the Commission precedent, affirmed by the courts, requires a remedy. There is no reasonable prospect of the situation self-correcting under the existing mechanisms of the System Agreement for equalizing only excess capacity and energy. As Entergy's witness Schnitzer pointed out to me, the System Agreement does nothing to equalize benefits and burdens on an annual basis "except by accident." Tr. 5816-18. The Agreement can either widen or narrow production cost differentials as circumstances vary. ETR 41 at 6-7 (Schnitzer). To Entergy, this confirms that the intent of the System Agreement is to balance production costs over time through the assignment of new resources. ETR IB at 14. From this, Entergy argues that therefore its "SSRP simply continues the tradition [of the rotational scheme] of using new resource acquisitions to narrow production costs whenever possible." ETR RB at 35. What Entergy overlooks is that the rotational scheme has been on long hiatus, perhaps for good planning reasons. But one of the results was the disparate impact on ELI of gas prices. Now that under the SSRP Entergy is planning new generation resources, and will factor in at least its view of proper timing and rotational assignment of them, perhaps there will be improvement. However, as I discuss above, and in a later section of this decision on the subject of the SSRP, there is no assurance that the SSRP will achieve rough production cost equalization, and every indication that it will not in the next five or so years. Moreover, Entergy's view that the SSRP or other resource plans will only narrow costs "whenever possible" underscores the need for an additional overarching remedy to bring the System back into rough production cost equalization when resource acquisitions and allocations, which can be complex decisions influenced by factors other than rough cost equalization, do not achieve that.

39. As noted by the Staff, the Commission's finding of undue discrimination in 1985 was premised on the integrated nature of the Entergy System, while its rejection of full production cost equalization in favor of rough production cost equalization as a remedy was premised on the historical ownership and financing by the Operating Companies. S IB at 7. *See Middle South Energy*, 32 FERC at 61,959. As the Staff also aptly points out, these principles are somewhat conflicting. *Id*. at 24. The Staff believes that: "The fully integrated nature of the Entergy System suggests that disparities should be small and not continue too long, while the Entergy history of individual company ownership, cost support and financing suggests that disparities have some justification." *Id*. at 24-25.

40. At this point in time, I agree with the Staff, although my judgment on the appropriate bandwidth limits and timing differs from the Staff's. As the years proceed, and I am thinking of many years, there may come a time when the newer generation resources have substantially displaced the older units still in operation. For these new resources, the applicability of any historical settled expectation of how the System would be operated, including under predecessor agreements to the current 1982 System Agreement, may fairly be open to reexamination.

41. Full production cost equalization is not required, and would have some consequences for the functioning of state regulation as discussed in a later section of this decision on that and a related alternative remedy proposed by the LPSC. The remedy I do provide is to restore rough production cost equalization, and insure that it will continue to exist if changes in available resources such as an SSRP type plan, do not achieve the numerical limits on disparity.

C. The Numerical Bandwidth Remedy Necessary to Bring the Entergy System into Rough Production Cost Equalization

42. As the Commission has noted in Opinion No. 292, rough production cost equalization is not a matter for the slide rule. 41 FERC at 61,618. Year to year variations, which are a far different concept than the current picture of at least five-ten years of large deviations in the same direction for an Operating Company, are to be expected. Therefore, I find it appropriate to impose a limit measured over a rolling multi-year average. I also find it appropriate to impose a higher annual limit to achieve some relief for the first year, to limit large swings in future individual years, and to start the multi-year rolling average towards smoother, achievable results. Selection of the numerical criteria is not an exact science. I am mindful of the large amount of dollars represented by percentage differences, which militate both ways in considering a reasonable balance to implement the Commission's unquantified standard. I find that the Staff and LPSC recommendation of a bandwidth of +/-5% from System average is reasonable, but I disagree with the LPSC that it should be applied each year. It is sufficiently less intrusive than full equalization, but is not so large as to permit undue discrimination. However, it will be sufficient and not undue discrimination, taking into account annual variations shown in the past record prior to 2000, and the fact that variation year-to-year always is part of any system planning and operation, to apply the +/- 5% limit to a rolling three-year average. Although this is not the main reason for selecting a rolling period of three years, it is consistent with the time-frame given by Entergy to get a modern Combined Cycle Gas Turbine (CCGT) unit into operation as part of its SSRP. ETR-13 at 18-19 (Harlan).

43. I also provide the remedy of an annual limit of +/-7.5% deviation from System average. The annual limit and the three-year rolling average limit each will apply in tandem in the future. The 7.5% limit allows for greater annual variation than 5%, but not so much more as to cause large annual swings in the amount of money needed to achieve the overall 5% criterion on a rolling three-year average basis. I think of the 7.5% annual limit as one of the means to assist in the implementation of my main criterion of the 5% rolling three-year limit. I also conclude that the historical record of deviations gives me some discretion in when to implement these remedies. I consider as part of the balancing the LPSC's reasonable desire to remedy the undue discrimination it has suffered since 2000, with the consideration that if the discrimination had been an aberration for only a few years, perhaps about three years, I would likely not have found the need for a

remedy. As a less significant, but still important consideration, I want to minimize the disruption to Entergy, the state commissions and ratepayers caused by the timing of implementation of this remedy. I therefore order that the +/- 7.5% annual remedy be effective beginning with all of the previous calendar year of 2003.[9] I direct that the first three-year period for the rolling average of +/-5% be 2004-2006. Thereafter there will be a new rolling three-year period each year. Thus the first year to which the annual +/- 7.5% bandwidth is being applied, 2003, will not be counted in the first three-year rolling average period.

44. The APSC and MPSC and Entergy believe that in setting a numerical disparity limit, only an upper limit is needed. They argue that the lower cost Entergy Operating Companies, EAI and EMI, should continue to have the incentive to try to keep their production costs as low as possible, citing AC-1 at 24-25 (APSC witness Berry). A&MC IB at 23. I disagree. Firstly, the Staff is correct that an undue preference is no more defensible than undue discrimination. S IB at 37. Secondly, the Staff and LPSC are correct that the APSC and MPSC argument is factually untenable. The Operating Companies are operated and centrally dispatched as one company, and thus could not have any individual company incentive, or act on it, to minimize production costs. *Id* at 35 n.84; LPSC RB at 38.

45. It might be helpful to provide an example of what I consider a reasonable way to apply the remedy. As an example only because of its convenience in the record, I use LPSC witness Baron's 2001 test-year analysis, which shows the disparities in total production costs among the individual Operating Companies. It is used here for illustration purposes only to show the application of the +/-7.5% annual limit. Naturally, as with any remedy, there would be a cost-shift effect among the Entergy Companies. The data are for a year to which I am not applying a remedy. Also, there are adjustments that Mr. Baron has made to the data that are consistent with the LPSC's positions, but which I have not accepted elsewhere in this decision. Mr. Baron further excludes interruptible load from the 12-CP (demand) responsibility ratio (Line 5), consistent with the LPSC's position. However, as all parties agree, that question is being decided in another Commission proceeding.

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[9] Presumably the tariff will be designed to provide that any adjustments necessitated by the numerical bandwidths will be paid (built into the rates) in the following year in each case.

Total Production Cost Deviation from System Average
2001 Test Year Applying +/- 7.5% Band
(x1000)

	A	B	C	D	E	F	G
1		ENTERGY	EGS	ENO	EMI	ELI	EAI
2							
3	Total Production Cost*	$5,363,662	$1,821,755	$354,199	$641,126	$1,567,738	$978,845
4							
5	12 CP Responsibility Ratio*	1.0000	0.3270	0.0552	0.1369	0.2478	0.2330
6	Allocated Fixed Production Costs*	$2,400,305	$784,977	$132,583	$328,639	$594,745	$559,362
7	Average Annual Energy Responsibility Ratio*	1.0000	0.3327	0.0543	0.1279	0.2577	0.2274
8	Allocated Variable Production Costs*	$2,963,357	$985,884	$160,864	$378,992	$763,613	$674,004
9	Total Allocated Production Cost* (Line6+Line8)	$5,363,662	$1,770,860	$293,446	$707,631	$1,358,358	$1,233,367
10							
11	Dollar Deviation* (Line3-Line9)	$0	$50,895	$60,753	($66,505)	$209,380	($254,522)
12	Percent Dollar Deviation (Line11/Line9)		2.87%	20.70%	-9.40%	15.41%	-20.64%
13							
14	Bandwidth (+/-7.5 %)			**7.50%**	**-7.50%**	**7.50%**	**-7.50%**
15	Production Cost at Bandwidth (Line9+/-0.075xLine9)			$315,454	$654,559	$1,460,235	$1,140,864
16	Deviation Above +7.5% Band (Line3-Line15)			$38,745		$107,503	
17	Deviation Below -7.5% Band (Line3-Line15)				($13,433)		($162,019)
18							
19	Accumulated Excess Deviation (D19+E19+F19+G19)	($29,204)		$38,745	($13,433)	$107,503	($162,019)
20	Accumulated Excess Allocated to ELI and ENO**	$29,204		$5,188		$24,016	
21							
22	Cost Shift Result Due to Setting +/-7.5% Band			$43,933	($13,433)	$131,519	($162,019)
23							
24	Percent Dollar Deviation by Imposing a +/-7.5% Band***		**2.87%**	**5.73%**	**-7.50%**	**5.73%**	**-7.50%**
25							
26	*LC-5 and LC-12						
27	**For ELI, B20x(F9/(D9+F9)).						
28	**For ENO, B20x(D9/(D9+F9)).						
29	***For ELI, (F15-F9-F20)/F9.						
30	***For ENO, (D15-D9-D20)/D9.						

Notes: Percent Dollar Deviations (Line 12) differ from Mr. Baron's percent dollar deviation shown at LC-5 since he divided Line 11 by Line 3 (production cost) instead of by Line 9 (allocated production cost). Also, the Line 12 Percent Dollar Deviations match closely with Mr. Baron's "% DEVIATION FROM SYSTEM AVERAGE" at LC-5, line 10, which are the deviations in total production cost from System average. In his exhibit, the total production costs on a cents per kWh basis reflect a load factor adjustment to fixed production costs. Furthermore, although no load factor adjustment appears in the spreadsheet example, since fixed production costs are not unitized on a cents per kWh basis, there will be a relatively minor difference because the LPSC includes fixed nuclear costs with the allocation for all fixed production costs (Line 6). Elsewhere in this decision, I agree with other parties that fixed nuclear costs should be allocated on an energy basis (Line 8). As can be seen from comparing Lines 5 and 7, the differences are not large.

46. As the spreadsheet demonstrates, LPSC's full production cost equalization method would shift $254,522,000 and $66,505,000 to EAI and EMI from the other Operating Companies ($321 million total). Under rough production cost equalization with a bandwidth of +/- 7.5%, however, the numerical remedy for the 2001 test year would have resulted in a cost shift of $162,019,000 and $13,433,000 to EAI and EMI, respectively, from ELI and ENOI ($175 million total). In this illustration, EGSI would be unaffected since it already is within the 7.5% bandwidth.

47. The numerical remedy would raise ELI's allocated production cost by 7.50% from $1,358,358,000 to $1,460,235,000. Nonetheless, ELI would still be over that level by $107,503,000. At the same time, EAI would be below the minus 7.50% level of $1,140,864,000 (0.925 x $1,233,367,000) by $162,019,000. Similarly, ENOI and EMI would have excesses above and below, respectively, even after establishing a +/- 7.5% bandwidth relative to their total allocated production cost.

48. Adjusting the total allocated production costs to the +/- 7.5% band levels would leave an accumulated excessive deviation of $29,204,000 since initially the percent dollar deviation for each individual Operating Company is different (Line 12 of the spreadsheet). Therefore, this amount will be pro rated to ELI and ENOI in proportion to their allocated total production cost (Line 9) to avoid discrimination between them. As the spreadsheet illustrates, the total production cost disparities are reasonably narrowed to and within the +/- 7.5% bandwidth after allocating the accumulated excess deviation (Line 24).

49. EGSI would have been included with ELI and ENOI in the allocation of accumulated excess deviation if it had turned out that the percent dollar deviation for ELI and ENOI had been reduced to EGSI's percent deviation and there still had been an excess dollar deviation left over. In other words, the three Operating Companies would have "come down" together in proportion to their allocated total production cost if this situation occurred.

50. No matter what the scenario, the end result is to ensure that for each calendar year beginning with 2003, no Entergy Operating Company is more than +/- 7.5% relative to System average, with the total allocated production cost (Line 9) as the System point of reference.

51. For the reasons stated above, I find that the LPSC has established that the Entergy Operating Companies no longer are in rough production cost equalization, and that without a modification of the System Agreement to include the numerical bandwidth remedy I hereby impose, it is unjust, unreasonable, and unduly discriminatory and preferential.

D. Should the Contract Price of Energy From the Vidalia Hydroelectric Power Plant be Fully Reflected, or Should an Adjusted Value be Used for the Purpose of Determining Whether the Production Costs of the Operating Companies Are Roughly Equal?

52. Forty miles below the Town of Vidalia, Louisiana, the United States Army Corps of Engineers runs a flood control program which diverts overflow waters from the confluence of the Mississippi and Red Rivers into the Atchafalaya River through a series of channels. The Vidalia Hydroelectric Power Plant ("Vidalia") was built at the location of this flood control project to harness the power of the water as it runs through the channel. S-1 at 48 (Sammon). The power plant consists of six turbines, each having a rated peak capacity of 32 MW, yielding a total nominal rated peak capacity of 192 MW. However, since Vidalia is a run-of-the-river hydroelectric project, the output of the turbines depends on the flow of the rivers. Therefore, Vidalia's average capacity is about 84 MW. ETR-23 at 44 (Louiselle).

53. Failing to independently obtain financing for the construction of the plant, the Town of Vidalia entered into an agreement with Catalyst Energy Development Corporation to form the Catalyst Old River Hydroelectric Limited Partnership. ETR-23 at 44 (Louiselle). On November 18, 1985, ELI (then Louisiana Power & Light) entered into a contract with the Catalyst Old River Hydroelectric Limited Partnership whereby ELI would purchase up to 94% of the output of Vidalia, with the Town of Vidalia purchasing the remaining 6% of the output. AC-13 (Vidalia Contract).

54. The LPSC advocates that the actual costs of Vidalia should be included in the production cost calculations because Vidalia is a System resource. According to the System Agreement, each operating company is to have generation, either owned or under contract, sufficient to meet the needs of its own customers. ETR-2 at ¶ 4.01. In the case of purchased capacity, the System Agreement states that the Companies, "with the consent of or under conditions specified by the Operating Committee, may agree to a contract by one or more of them, for the purchase of capacity and/or energy from outside sources for the account of a Company or Companies." ETR-2 at ¶ 4.02. The LPSC submits that at the time that Vidalia was planned, the Entergy Operating Companies ordinarily performed their own planning studies and presented their findings to state regulators. However, the resource additions were still planned as a part of a greater effort to acquire additional generation capacity for the benefit of the System. *See Middle South Energy, Inc.*, Opinion No. 234, 31 FERC ¶ 61,305, at 61,652; Tr. 4186-87 (Gallaher).

55. The LPSC claims that ELI planned the acquisition of Vidalia as a System resource, with the knowledge and consent of the Entergy Operating Committee. Jerry Saacks, who was the chairman of the Entergy System Operating Committee and an officer of the board of directors of ELI during 1984-85 when the economic analyses determining whether Vidalia was a worthwhile resource to acquire were being conducted,

oversaw the effort to obtain Vidalia for ELI. Tr. 4858-59 (Harlan). Mr. Saacks kept the Operating Committee informed as to the status of the ongoing discussions to acquire Vidalia. Tr. 4860-61 (Harlan). The LPSC suggests that the fact that one of his reports detailing the efforts to obtain Vidalia was in the Operating Committee's minutes stands as proof that Entergy was involved in the acquisition of Vidalia as a System resource, not as an ELI-only resource. LC IB at 74.

56. In 1984, Mr. Harlan, working as the chair of the System Planning Committee, prepared an economic analysis of Vidalia's effect on the customers of ELI. Tr. 4862 (Harlan). The analysis examined the effect of the Vidalia contract in comparison with a mix of coal, gas and oil energy. Because ELI did not own operational coal units during that time, the inclusion of coal in the economic analysis represented the marginal costs for energy that would be available through the System. Tr. 4880 (Harlan). Mr. Saacks presented Mr. Harlan's economic analysis to the ELI Board of Directors, which stated that the economic benefits of the Vidalia project would approach $5 billion over the life of the agreement. Tr. 4865 (Harlan). The ELI Board ultimately approved Vidalia, and authorized ELI to negotiate a contract for the purchase of Vidalia's power that would be approved by the LPSC. LC-51 (Minutes of August 26, 1985).

57. The LPSC further points to the deposition of Jack King, who was chairman of the Operating Committee when the Vidalia contract was approved in 1986. Mr. King stated that long term purchases, such as what ELI entered into with Vidalia, had to be evaluated by the Operating Committee for inclusion in the intercompany billing and for inclusion in the load and capability forecast. Without approval by the Operating Committee, Mr. King testified, a purchase by an Operating Company could not be listed in the load and capability forecast. LC-127 at 114-17 (King). Mr. King further testified that he knew of the Vidalia purchase and recalled the Operating Committee's discussion and approval of the Vidalia contract for inclusion in the load and capability forecast. LC-127 at 127-30 (King). Supporting Mr. King's deposition testimony is a copy of the minutes from the October 9, 1986 Operating Committee's conference call, noting the addition of Vidalia as a resource in the load and capability forecast. LC-80 at C-13. Frank Gallaher, who was President of Entergy Services, Inc., after some fencing with the cross-examiner, agreed with Mr. King's testimony that Vidalia was approved for inclusion in the MSS-1 billings for reserve equalization. Tr. 4202-03; *see also* Tr. 4192-4203 (Gallaher). Accordingly, since ELI's purchases from Vidalia benefit the System as a whole just as any other System resource, the LPSC advocates that ELI be given full production cost credit for the price of energy that it pays under the Vidalia contract.

58. Entergy disagrees with the LPSC's argument that Vidalia is a System resource. It notes that the absence of System planning and approval, when combined with the unusual structure of the Vidalia contract, demonstrate that Vidalia was never intended to be considered a System resource. ETR IB at 44. Entergy points to the prior decisions of the Commission regarding allocation of production on the Entergy System. It argues that the

Commission has previously held that Entergy's decision to build nuclear power plants was part of a centrally planned effort to dramatically increase the amount of nuclear capacity to serve the base load needs of the System as a whole. *See System Energy Resources, Inc.*, Opinion 292, 41 FERC ¶ 61,238 at 61,618-619 (1987). Furthermore, they argue that the Commission has held that increases in individual Operating Company costs caused by the decisions of local retail ratemakers were not relevant to the calculation of production costs against those of the system as a whole. *See Middle South Energy, Inc.*, Opinion 234-A, 32 FERC ¶ 61,424 at 61,959 (1985). Applying this precedent to Vidalia, Entergy submits that since there is no record of a System-wide drive to increase hydropower, then Vidalia cannot be considered a System resource. Likewise, Entergy posits that if the earlier decisions of the LPSC have created present burdens on the ratepayers of ELI that the LPSC now regrets, the LPSC should not be allowed to export the unfortunate consequences of its poor decision-making to the rest of the ratepayers on the Entergy System. ETR IB at 46-47.

59. Entergy characterizes Vidalia as a generation project undertaken not with an eye towards fulfilling System generation needs, but towards satisfying the political and economic policy needs of the State of Louisiana, at the direction of the LPSC. ETR IB at 50. Mr. Louiselle, testifying for Entergy, stated that ELI began negotiations for Vidalia's power in 1982, and eventually arrived at a phased-in rate schedule that was approved by the LPSC in 1985. The effect of the approved rate schedule was to limit the cost to the ratepayers in the early years, ramp the cost up to a high plateau in later years, finishing by falling and leveling off rate levels by the end of the contract. ELI's earlier contract proposal for Vidalia was rejected by the LPSC, according to Entergy, because the initial costs for the ratepayers were too high, delaying the onset of benefits to the consumers until much later in the agreement. ETR-23 at 45-47 (Louiselle). In return, the LPSC allowed ELI to "recover the total cost of energy over the entire duration of the Contract from its customers by including the total cost incurred as a fuel cost in the monthly fuel adjustment charges." LC-83 at 2 ¶ (A)(3) (Vidalia Contract Order No. U-16246-A). Entergy submits that the effect of this allowance was to shield ELI from the risks and burdens in such a large capital project as Vidalia, such that ELI and its sister operating companies would not be responsible for financing the large capital obligations required to go forward with construction. ETR IB at 50.

60. Entergy disputes the importance of the inclusion of Vidalia in the Load and Capability Forecast. Entergy argues that the inclusion of resources in the Load and Capability Forecast does not confer approval of the resources, but merely was used as a tool to determine how much energy was available to the individual Operating Companies so that the Operating Committee could plan future resource acquisitions for the benefit of the System. ETR IB at 54. Entergy further argues that the inclusion of Vidalia in the Load and Capability Forecast was not indicative of approval as a system asset, but merely that the project existed as a source of power.

61. The Arkansas and Mississippi Public Service Commissions concur with Entergy in its assessment that Vidalia should not be considered a System resource, but as an ELI resource. They dispute the LPSC's assertion that the study on Vidalia's effects on ELI's ratepayers that was performed at the request of Mr. Saacks looked at the effects of the addition of Vidalia on the System. They assert that the deposition testimony of Mr. Saacks establishes that the ELI Vidalia study examines Vidalia against the ELI avoided cost, not the System avoided cost, as would be required if the study was truly to examine the effects of Vidalia on the System. AC-49 at 211-212. The Arkansas and Mississippi Public Service Commissions find further fault in the LPSC's theory that since the persons making decisions regarding Vidalia for ELI were also System decision makers, their actions implied approval on behalf of the System. If this were true, they note, there would be a record somewhere in the System Operating Committee minutes of the approval of Vidalia as a System resource. A&MC IB at 46. They find that the lack of any discussion whatsoever underscores the fact that Vidalia was planned as an ELI-only resource, not as a System resource.

62. Staff also agrees with Entergy that Vidalia should not be considered to be a System resource, since it was planned as an ELI-only resource. Staff argues that since the purchase was initiated outside of the System Operating Committee, where proposals for System generation projects are normally assessed, that demonstrates that Vidalia was not intended to be a System resource. S-1 at 50-51 (Sammon). Next, Staff argues that because the contract rates were not developed on traditional cost of service principles, but were based on ELI's avoided costs, this further demonstrates that Vidalia was planned as an ELI-only resource. S IB at 46. Finally, because the contract that was approved by the LPSC flows through all of ELI's costs to the ratepayers under a fuel adjustment clause, this demonstrates that Vidalia was not planned as a System resource. S-1 at 57 (Sammon).

63. CNO also agrees with Entergy that since the Vidalia contract was not entered into in order to meet System needs, it should not be considered to be a System resource. CNO takes issue with the fact that substantial tax benefits associated with the Vidalia contract have been exclusively retained by ELI. According to LPSC Order No. U-20925 (CNO-1), ELI is to share with ELI customers a portion of the tax deduction that it believed it could take. The benefits to ELI customers could last from 8 to 30 years, ranging from a minimum of $88 million to as much as $600 to $700 million over the life of the contract. CNO-1 at 3-4. The effect of this rebate if Vidalia was to be treated as a System resource, assuming a market rate of $40 MWh, would be to cap the expenses for ELI ratepayers from the Vidalia contract at around $60 per MWh, leaving the ratepayers of the other Entergy Operating Companies to pay the full Vidalia price of upwards of $200 per MWh. A&MC RB at 49. Therefore, the fact that the tax benefits of Vidalia are to be shared with ELI alone demonstrates that Vidalia was intended as an ELI-only resource, and should not be treated as a System resource. CNO RB at 20-21. In response, the LPSC stated that any reduced tax cost from Vidalia that would be available to Louisiana ratepayers

should also flow through to all of the other System ratepayers. The availability of this deduction would reduce the per-books costs in the same way that other tax deductions flow through to System ratepayers. LC RB at 58-59.

64. The solution that Entergy proposes is to credit ELI's purchases under the Vidalia contract to its production costs at the annual price of replacement energy under Service Schedule MSS-3. Both the Arkansas and Mississippi Public Service Commissions and FERC Staff support Entergy's proposal. A&MC IB at 44; Staff IB at 42-43. Entergy advocates that this is an appropriate production cost credit for Vidalia's energy since that is the price that ELI would have to pay to purchase power from other resources had it not been forced to purchase power from Vidalia. Service Schedule MSS-3 functions to allocate energy each hour among the Entergy Operating Companies on an after-the-fact basis in a manner that each Operating Company that generates power in excess of its needs is deemed to sell that energy into the System Exchange for the use of the other Operating Companies in the Entergy System. The ultimate effect would be to place a value on the power from Vidalia of about $37 per MWh. ETR-23 at 42 (Louiselle); Tr. 2942 (Larkin). Therefore, rather than credit ELI's production costs with the full contract price of Vidalia, only $37 per MWh would be credited towards ELI's production costs. This methodology is supported by Entergy because it not only eliminates the cost shifting effect of sharing Vidalia's escalating high cost structure with the other Operating Companies, but also forces the LPSC to keep its word that the costs of Vidalia would be born by ELI's ratepayers. ETR IB at 44-45.

65. After examining the evidence on the record, I find that there is sufficient evidence to conclude that Vidalia was planned as a resource for the benefit of the Entergy System. Entergy has treated Vidalia since its inception as a resource that would provide benefits for the System as a whole. After Vidalia went into service, it provided energy that was ultimately used to serve the loads on the System, which was noted by the System Operating Committee. Furthermore, to value Vidalia's energy at the MSS-3 rates as Entergy and the other parties suggest would have the effect of unfairly devaluing Vidalia's economic contribution to the stability of the System. Accordingly, it would be proper to recognize Vidalia as a System resource for the purposes of calculating ELI's production costs.

66. Under Paragraph 4.02 of the System Agreement, the Operating Committee has the right to specify special conditions regarding the treatment of any purchase of power by one of the Operating Companies. ETR-2 at ¶ 4.02. In 1980, the Entergy Operating Committee put conditions on the purchase of power from the Southern Company by EMI. Because there was an objection in the Operating Committee, EMI received no MSS-1 capacity credit for the power purchase. Tr. 4898-4900 (Harlan). However, it should be noted that there was no evidence presented whatsoever that the Operating Committee

voiced a similar objection regarding Vidalia.[10] Unlike the Southern Company purchase, Vidalia was given 81 MW of capacity credit under MSS-1 in 1990 by the Operating Committee. ETR-77 at 3; Tr. 4903 (Harlan). The credit given to Vidalia is shown on the System bills. LC-94 at 3 (showing 89 MW of capacity credit accorded to the power purchased by ELI from Murray Hydro (Vidalia)). Since the energy from Vidalia is credited in MSS-1, it means that the System can use the energy for its needs and does not have to purchase replacement energy. Accordingly, if ELI did not have the energy from Vidalia during the summer peaking months, Entergy would have to purchase additional energy to replace the lost generation from Vidalia. Tr. 4906-08 (Harlan).

67. Entergy argues that the fact that ELI alone presented studies to the LPSC for approval of the Vidalia contract showing Vidalia's impact on ELI ratepayers is evidence that Vidalia was intended as an ELI-only resource. However, the LPSC has demonstrated that when Vidalia was approved by the LPSC, it was part of the accepted common practice in the Entergy System that when a new facility was planned, the responsible Operating Company would deal with the regulatory entity of that jurisdiction to obtain the necessary approvals on behalf of the System. This included the presentation of operating company specific studies for each facility. Tr. 4103-08 (Gallaher) (discussing the fact that when EAI or EMI needed approval for facilities, they presented company-specific proposals to the APSC and the MPSC, respectively). Therefore, the fact that ELI was alone in its dealings with the LPSC is not indicative of the fact that Vidalia was planned as an ELI-only resource, but merely that ELI was following established System protocol, consistent with the fact that the direct regulatory authority of the State (or CNO) regulatory body is over its jurisdictional Operating Company.

68. Additionally, the LPSC points out that Entergy has consistently treated Vidalia as part of the System in its previous calculations of production costs for purposes of determining whether the Entergy System was in RPCE. In the 1993 Entergy/Gulf States merger case, Entergy included the full costs of Vidalia when presenting the production costs of ELI for the purposes of proving that the Entergy System would remain in RPCE after the merger. Tr. 4204-06 (Gallaher); LPSC IB at 85. In the 1995 Arkansas decommissioning case, Entergy again presented a calculation of ELI's production costs including the full price of Vidalia for the purposes of showing that the companies

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[10] An analogous situation regarding purchase of energy occurred with the purchase of 250 MW of energy in the summer of 2001 to replace the energy lost from ENOI's Michoud Units 2 and 3. The Operating Committee objected to the purchase, and placed reservations on how the purchase was to be handled. Ultimately, the Operating Committee assigned 100% of the purchase to ENOI, and did not include the purchase in the MSS-1 calculations. LC-50 at 32-33 (Kollen); LC-53 at 3-4 (Entergy Operating Committee Minutes of July 3, 2001).

remained in RPCE. Tr. 4206 (Gallaher). Finally, in the 2000 Retail Competition case, Entergy evaluated the costs of all of the Operating Companies to present the argument that the Companies were in RPCE. Their evaluation of ELI's costs included Vidalia's full contract price. *Id* at 4207-10 (Gallaher).[11]

69. Arguably, positions taken for litigation purposes are not always indicative of a party's normal course of action. However, it is important to note that this proceeding marks the first time that Entergy has taken the position that Vidalia is not a system resource. What is even more significant is the fact that even in internal studies done for the use of the System Operating Committee to determine whether the System is in RPCE, Vidalia's full contract costs have always been included in the calculation of ELI's production costs, until the present case. Tr. 4211-15 (Gallaher); LC-129 (Entergy Data Response). Therefore, given that Entergy recognizes Vidalia's contribution to the System though MSS-1 and has previously included it as part of the System for calculating overall production costs for purposes of RPCE, it follows that the power from Vidalia is used for the System's benefit to serve one load: the System load. Tr. 4217-18 (Gallaher).

70. The resolution of the issue of the System-status of Vidalia leaves this question: If Vidalia has been established as a System resource, should the costs be accepted at the actual contract levels, or should there be an adjustment applied to levelize Vidalia's contract costs over the life of the contract? Consistent with its view of Vidalia as a System resource, the LPSC believes that the full contract price for Vidalia's output should be counted as part of ELI's production costs. LC RB at 59. If Vidalia is to be treated as a System resource, then the LPSC believes there should be no special treatment accorded to Vidalia which would have the effect of understating ELI's true production costs.[12]

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[11] Entergy's argument that the instant case is the only proceeding since the Grand Gulf case where a party has requested production cost reallocation may be technically correct, but it's misleadingly immaterial. Entergy's claim that the allocation of Vidalia's costs in the aforementioned cases is not relevant since the treatment of Vidalia's costs was not an issue is disingenuous. *See* ETR RB at 32-33. The treatment of *all System production costs* to determine whether the relative production costs of the Operating Companies were or would remain roughly equivalent was the *very* reason that the production cost studies were performed in the first place.

[12] If Vidalia's full contract costs were "stuck" to ELI and not counted for purposes of determining relative costs of the Entergy Operating Companies, this would greatly decrease ELI's total production costs relative to the other Entergy Operating Companies. This is because if that were the determination, the production costs of Vidalia would be "repriced" to ELI for purposes of the comparison with the other Entergy companies at the

71. An alternative that was explored at the hearing would be to levelize the contract for Vidalia so as to eliminate the effects of the escalating costs of the power purchase contract path, thus giving Vidalia a uniform value for its energy contribution to the system over the life of the contract. ETR IB at 45. Entergy witness Harlan presented an alternative where the contract price would be levelized at $91.40/MWh, based on a discount rate of 12.45%. S IB at 48; Tr. 5350-52 (Harlan); LC-157. Staff concurs with Entergy in suggesting that the contract rates for power from Vidalia should be levelized on a present value basis to place all system rate payers on an equal footing going forward. S IB at 45-48. The LPSC is opposed to Entergy's proposal to levelize Vidalia's contract cost because it vastly distorts the contribution of the ratepayers, and because it is premised on an inaccurate discount rate. Tr. 5356 (Harlan); LC RB at 57-58.

72. After considering the competing proposals of the LPSC and Entergy, I find that the Vidalia contract should be accepted at full contract value, rather than at a levelized value. The contract was agreed to by ELI for the System, and the energy output provides a benefit for the System. The phased-in contract rate path was chosen by ELI and the LPSC to protect the ELI ratepayers from rate shock, as the Vidalia plant was going on line close to when the ELI ratepayers were paying a "very significant portion of the financing costs" of the Waterford 3 nuclear plant. Tr. 4863 (Harlan). It was in the interests of the Entergy System that wanted to acquire this purchased power resource to find a means by which the state regulator with jurisdiction, here the LPSC, would approve a contract. Entergy has long accepted the full Vidalia contract costs as part of the total production costs of the System and should not be permitted to reject them now because of the upcoming increases scheduled in Vidalia's rate path.

MSS-3 low variable production cost for this hydropower. However, although not material given my determination not to "reprice" Vidalia at the MSS-3 level, I note that rough production cost equalization still would not exist currently even if Vidalia is repriced. *See e.g.* ALJ-3 at 1 (presenting the differences for the years 2000-2005 as percent deviations of the Operating Companies from the System average, *inter alia,* caused if Vidalia is given the full contract cost or if Vidalia is repriced as MSS-3 energy). For example, Entergy's SSRP base case adjusted for load factor with Vidalia repriced shows EAI at -13% and ELI at +8%. Entergy's own projections of its optimal SSRP base case for 2003-2010 (with Vidalia repriced) show that EAI is outside the bandwidth at -9%, and ELI is at +5%. *See* ETR IB at 10 n.9, 11 and Attachment 1 (citing the record bases for the data).

E. Entergy's Strategic Supply Resource Plan Will Not Assure Roughly Equal Production Costs

73. Entergy's Strategic Supply Resource Plan ("SSRP") is a long-term power supply plan that includes the purchase of base load and load-following generation from 2003 through 2012. Through a mix of purchases of solid fuel generation and combined cycle gas turbine ("CCGT") generation, long and short-term contracts, and System-owned and merchant-owned generation, Entergy seeks to "lower System production costs, improve the portfolios of individual Operating Companies, reduce production cost disparities, and reduce System and ELI exposure to gas price volatility." ETR IB at 62.

74. Entergy has outlined six major objectives of the SSRP: Reliability, Base Load Production Cost Reduction, Load Following Production Cost Reduction, Portfolio Enhancement, Risk Mitigation through Price Stability, and Risk Mitigation through Supply Diversity. Entergy states that it is currently short on capacity to meet the 2003 peak plus reserve requirement, short of base load resources for the 2003 firm base load requirement, and that there is a projected increase in base load requirements by 2007. Furthermore, Entergy states that it lacks modern, efficient CCGT generation, and that most of its existing load-following generation is outdated and inefficient when compared to CCGT generation. Finally, Entergy estimates that the existing base load resources can only provide less than 60% of the long-term firm energy requirements, and states that there are "[m]ajor transmission dependencies in Amite South and WOTAB"(portions of the Entergy service area). ETR-14C (Exh. DCH-1 at 4).

75. Entergy states that it has designed the SSRP to attempt to address these deficiencies through selective and targeted resource acquisition. The Purchased Power Supply Procurement Plan targets the goals of diversifying the resource portfolio and capping the price exposure to short and mid-term purchased power price uncertainty and volatility by limiting the dependence on purchased power to what capacity Entergy could conceivably finance and build in a three year period of time (e.g. 3 typical 500 MW projects, totaling 1500 MW), and by implementing a "portfolio approach" to resource procurement whereby multiyear contracts would be scheduled to expire at various times over a three year period. ETR-14C at 6. The Long-term Controlled Resource ("Life of Unit" Capacity) Plan targets the goals of maintaining self-supply options, diversifying the resource portfolio, and minimizing transmission delivery costs by identifying possible repowering/CCGT projects, and by improving transmission capabilities in constrained areas. ETR-14C at 8-9.

76. Entergy asserts that implementation of the SSRP will have profound effects on the production costs of the individual Operating Companies, helping to bring all of the Operating Companies closer to the System average production cost over the period from

2003-2010. ETR-12 at 14 (Harlan). Entergy states that even under the "Spike and High Trend" Natural Gas Case[13] with Vidalia at its full contract price, simulating gas prices at the high end of the expected spectrum, both ELI and ENOI's production costs still move towards the System average. ETR IB at 64; ETR-107C.

77. Strongly opposed to the SSRP, the LPSC views it as nothing more than a contrived method to avoid FERC intervention in achieving system equalization. Furthermore, by the LPSC's analysis, it doesn't even do that. What the SSRP manages to do, according to the LPSC, is to give illusory promises of system equalization, while inequitably shifting costs and balkanizing System planning. LC IB at 87-88. The LPSC disputes the accuracy of Entergy's modeling, thereby questioning whether the SSRP will ever achieve Entergy's stated results. LC RB at 59-60. *See also* LC-27 at 54-57 (Baron); LC-70 at 19 (Hayet); Tr. 2290-2304 (Hayet); LC-87C (workpapers); Tr. 5030-32 (Harlan); LC-147 (effect of different versus consistent merchant modeling).

78. Underlying many of the comments on the SSRP was a level of uncertainty as to whether the SSRP could or would be implemented as proposed by Entergy. TECO Power's comments, as one of the merchant generators in the Entergy System area, question whether Entergy would follow through with the SSRP without some sort of integral mechanism to encourage compliance with the proposal. TPS IB at 2-3. Further underscoring the uncertainty regarding the SSRP, a pending FERC proceeding is examining how Entergy is structuring its purchase power agreements, and whether there exists a level playing field for merchant generator bidding in the Entergy System. *See generally Entergy Services, Inc. et al.*, Docket No. ER03-583-000 *et al*.

79. It is apparent that the SSRP alone will not achieve rough production cost equalization on the Entergy System. Even using Entergy's own data regarding the optimal scenario for the SSRP, but with Vidalia at full contract price, the SSRP fails to bring the System within rough production cost equalization. ETR-107C at 1. From 2003 through 2010, the last year projected, Entergy's own data for the SSRP base case shows both ELI and EAI outside of the rough production cost equalization bandwidth established earlier in this opinion. *Id.* Moreover, for that same period, Entergy's data for the very possible, if not more likely, high gas case with Vidalia at full contract price shows EAI at -15% and ELI at +9% of System average, in excess of the bandwidth. *See* ETR IB at 10 n.9, 11 and Attachment 1 (citing the record bases for the data). While there is a general trend closer to System average for the first few years from -23% for EAI in 2003 to -12% in 2006, EAI's deviation plateaus at -12% for the remainder of the projected period. Likewise, ELI trends generally toward the System average for the first

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[13] It should be noted that there were multiple variations of the SSRP produced to account for the uncertainty in projected natural gas prices.

few years going from +12% in 2003 to +8% in 2006, but then plateaus at +7% for the remainder of the projected period to 2010.[14] Accordingly, I find there is no assurance that, as presently planned, Entergy's SSRP will restore roughly equal production costs. If, due to changes in Entergy's SSRP plan or any other circumstances that unfold in future years, the rough production cost equalization bandwidth is satisfied, then that overarching remedy established to assure rough equalization would not be triggered.

III. HOW SHOULD PRODUCTION COSTS (FOR EXAMPLE, AFUDC, DAP AND GRAND GULF RETAINED SHARES, TEXACO REFUND AND LOAD FACTOR ADJUSTMENT) BE STATED CONSISTENTLY AMONG THE OPERATING COMPANIES.[15]

A. Avoided Allowance for Funds Used During Construction

80. The LPSC states that retail regulators can treat construction costs in two different manners. One approach does not permit Construction Work in Progress (CWIP) in rate base during construction. Instead, it is capitalized into gross plant in service as Allowance for Funds Used During Construction (AFUDC) and it is paid for by ratepayers only after the plant construction is completed and the plant is in commercial operation. The other approach permits a company to earn a return on construction investment *during the construction period.* Under this approach, carrying costs (return on investments) are paid currently by retail ratepayers rather than capitalized into the cost of plant as AFUDC. LC IB at 65.

81. The Staff explains that public utility regulation has generally allowed only "used and useful" capital items in the rate base for recovery from ratepayers. This means that expenditures on CWIP are excluded from rate recovery until the new facilities become commercially operational. The expense of financing construction to serve customers is recognized as a legitimate business expense which is permitted at some time to be recouped from ratepayers. The financing costs of construction are called AFUDC and are accrued during construction and allowed in rate base when the plant is placed in service.[16] Depreciation provisions included in rates charged for utility service are a way

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[14] Even Entergy's own projected disparities for this period for its SSRP base case with Vidalia repriced at the low cost MSS-3 rate (thereby artificially depressing ELI's production costs substantially) show EAI outside the bandwidth at -9%, and ELI at +5%. *See* ETR IB at 11.

[15] As all parties agree, the issue of whether interruptible loads should be included in calculating load responsibility ratios will be decided in another proceeding now on appeal before the Commission. *Louisiana Public Service Comm'n. et al. v. Entergy Corporation, et al.*, Dockets EL00-66-000, EL95-33-002 (consolidated).

[16] *Louisiana Power & Light Co*., 14 FERC ¶ 61,075, at 61,114 (1981).

the AFUDC charged to construction costs is recoverable from customers when the completed plant is placed into service. S IB at 41; LC-181 at 1 (ELI 1984 FERC Form 1: F. AFUDC – Notes to Financial Statements); *LP&L*, 14 FERC at 61,119.

82. However, to the extent FERC follows a different approach and approves the inclusion of CWIP in rate base, the utility must show that it will discontinue the capitalization of AFUDC on such amounts of CWIP as may be permitted by FERC to be included in jurisdictional rate base. *Id.* at 61,117-120. One of the accounting and ratemaking claims of the LPSC through its witness are that the two different treatments granted to the EOCs created timing differences that must be addressed. The LPSC opines that for the companies granted current earnings on CWIP, the gross plant is understated compared to those companies that capitalized CWIP as AFUDC for their respective gross plant in service. The LPSC argues that adjustments must be made to put the companies on a comparable basis for purposes of this case. LC IB at 65.

83. As pertains here the LPSC allowed the *current recovery* of carrying costs on CWIP for ELI's Waterford 3 unit and EGSI's River Bend unit and the PUCT followed the same path for River Bend. The LPSC alleges that at least two things happened as a result of those decisions. First, Louisiana and Texas ratepayers incurred prepayments of plant costs for the Waterford 3 and River Bend nuclear units. Second, as a result of those ratemaking decisions the gross plant costs for those companies were hundreds of millions of dollars lower than plant costs for the operating company jurisdictions that did not permit CWIP in rate base. *Id*; LC-8 at 13.

84. The Staff agrees with the LPSC's concept of adding back an adjustment for avoided AFUDC, if necessary, but Staff does not agree with the actual adjustment or the value of the adjustment claimed by the LPSC. Staff believes that the FERC Form 1 amounts should already reflect a fully capitalized value for AFUDC and no additional adjustment to production costs for avoided AFUDC is needed. S IB at 42; S-8 at 88 (Patterson). The LPSC rebuts Staff's position by stating that only the wholesale portion (a very small portion) is reflected in FERC Form 1 amounts. LC RB at 45.

85. No one protests the fact that the plant costs of both Waterford 3 and River Bend would have been higher if the LPSC and the PUCT had not permitted current earnings on CWIP. *Id* at 66; LC-50 at 10 (Kollen); Tr. 3113-17; Tr. 5483 (Louiselle). But there are numerous reasons explained by Entergy and Arkansas, with which I agree, as to why such a large proposed adjustment, shifting millions of dollars in net plant related costs from ELI and EGSI to the other operating companies, has not been justified.

86. As explained by the APSC and the MPSC, the LPSC, through its witness Kollen, originally proposed an artificial increase of $470 million[17] in ELI's gross production plant and originally proposed an artificial increase of $302 million in EGSI's gross production plant. A&MC IB at 36; AC-1 at 36 (Berry). The effect of this proposal is to increase ELI's production costs relative to the System average by approximately $43-44 million[18] and increase EGSI's production costs relative to the System average (ultimately by less than one million dollars). This action also tends to decrease estimates of EAI's, EMI's, and ENOI's production costs relative to the system average. AC-1 at 35; Tr. 1761-62 (Kollen); ETR IB at 36-37.

87. The APSC and the MPSC refute the LPSC's claims that such an adjustment is necessary to eliminate "timing differences that must be removed if the plant-related costs of the Operating Companies are to be computed on a comparable basis." LC-50 at 9 (Kollen); A&MC IB at 37. The APSC and the MPSC have shown that there are in fact no timing differences, as alleged by the LPSC, and that the LPSC proposed gross plant addback will in fact distort the cost differentials among the EOCs. The record shows that the LPSC's arguments ignore the fact that CWIP was allowed in rate base in lieu of granting ELI and EGSI a higher return on equity. The CWIP payments were allowed by the LPSC and the PUCT primarily to provide financial stability to the two EOCs. ETR-23 at 32-33 (Louiselle). In addition this approach was chosen by the LPSC instead of allowing the alternative of greater allowed returns on equity. *Id*.; A&MC IB at 37.[19] The record also shows that EAI (then AP&L) had difficulty financing its construction program from the mid-1970s through the early 1980s and was authorized rates of return

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[17] Mr. Kollen originally calculated the Waterford 3 gross plant adjustment as approximately $471 million but revised it downward to $421 after Mr. Louiselle's testimony. ETR-67, 68 (Kollen Deposition Exhs. 1 & 2). The net plant value for avoided AFUDC is approximately $254 million, consisting of a gross plant amount of $421 less accrued hypothetical depreciation of $167 million. ETR-69 at 2 of 11 (Kollen Deposition Exh. 3).

[18] Applying the $254 million net plant value times an approximate all inclusive rate of return of 17 percent.

[19] The LPSC explained three choices when a utility has large construction programs and financial strains. The regulatory body can refuse to take any action, it can increase the fair rate of return to a higher than normal level, or it can decrease or eliminate the AFUDC entry (allow CWIP in rate base) resulting in higher rates immediately but lowering the rate base for future customers. LC-111 at 8 (*Louisiana Power and Light Company*, Order No. U-14690-A (La. Pub. Serv. Comm'n, 1981) citing *Ex parte Gulf States Utilities Co*., Order No. U-14495 (La. Pub. Serv. Comm'n, 1980). *See also* LC-113 at 8 (*Louisiana Power & Light Company, ex parte*, Order No. U-15684 (La. Pub. Serv. Comm'n, 1984) – LPSC Order U-15684).

that were higher than they would have been had the APSC allowed CWIP in rate base. Tr. 3692-3694 (Berry). LPSC witness Kollen conceded that if one set of customers paid higher rates through a return premium and another paid higher rates through CWIP, then there would be no timing differences. Tr. 1936-39.

88. While Mr. Kollen stated that a return premium is "too difficult to quantify" (Tr. 1930), it has been demonstrated that the avoided AFUDC quantification is difficult to calculate and fraught with uncertainty. Mr. Kollen's workpapers characterized his avoided adjustments as rough and very rough (ETR-67 and Tr. 1726-31) and he called them a reconstruction. Tr.1727. Also during the hearing it was pointed out that the calculations for adjustments for EGSI were overstated by about $296 million. Mr. Kollen admitted the error and reduced the EGSI avoided AFUDC adjustment for gross plant from $302 million to $6 million. Tr. 1734-36. If the avoided AFUDC adjustment for EGSI is $6 million, the rate impact among the EOCs would be a maximum of a relatively insignificant amount of approximately $1 million ($6 million times about 17%). In addition, there is ambiguity as to the appropriate level of CWIP in an LPSC order—either $900 million or $1.2 billion. *See* A&MC IB at 40-41. Finally, as discussed by Entergy witness Louiselle, the different jurisdictions use *different* depreciation and decommissioning accrual rates which have an effect on the net plant and which would involve great effort spanning many past years to attempt to determine the appropriate adjustments to attain an approximation of comparability for the plant costs for the EOCs. *See* ETR-23 at 34.

89. The "avoided" AFUDC amounts are artificial or reconstructed costs not reflected in the accounting records. The relevant LPSC and PUCT orders involved prudence decisions. As explained by the APSC and the MPSC, the end result of those decisions was a level of costs deemed prudent and which included whatever amount of AFUDC was in that amount. A&MC IB at 41-43. If the LPSC and the PUCT had required the booking of AFUDC consistent with Mr. Kollen's view, the actual costs of Waterford 3 and River Bend would have been higher, but the imprudence disallowance would most likely have also been higher. The amount of prudent River Bend costs and Waterford 3 costs would not likely have changed. ETR-23 at 29-30 (Louiselle). While not bound by the retail regulators' disallowance of plant costs due to a finding of imprudent costs for Waterford 3 and River Bend, I find neither evidence nor reason here to allow costs that have been determined to be imprudent by a state jurisdiction in one arena to be allowed in setting the wholesale rates of any of the EOCs in the context of comparing production costs among the EOCs. This would in effect allow one state jurisdiction to pass costs not allowed by it to the ratepayers of other jurisdictions. For this reason, I also am rejecting below the LPSC's attempt to include the disallowed costs from the River Bend Deregulated Asset Plan (DAP) for purposes of comparing EOC production costs.

90. The LPSC has asked me to take official notice of twelve various state regulatory agency decisions issued during the time period in which LP&L was allowed CWIP in rate

base. See LC RB at 43-44 and LC RB Attachments 1 and 2. The APSC filed an answer on November 21, 2003, arguing that the LPSC's actions were improper, and that the Commission should not take official notice of the state regulatory agency decisions. The APSC argues that the listed case excerpts should have been offered into the record during the hearing so that the other parties would have had the opportunity to cross-examine the sponsoring witness on these case excerpts. The APSC further argues that because of the delay of the LPSC in offering the state regulatory agency excerpts, the LPSC has unfairly denied other parties the opportunity to respond to and challenge the new information. See Response of the APSC to the Motion of LPSC at 1-3. On December 3, 2003, the LPSC filed a reply to the opposition of the APSC, arguing that it is not necessary for FERC to take official notice of state regulatory agency decisions, as mere citation to the state decision will suffice. However, since many of the cited decisions were unpublished, the LPSC attached them as a courtesy. See Reply to Opposition of the APSC to the Taking of Official Notice of Decisions of State Regulators at 3-4.

91. After reviewing the facts and the legal memoranda filed by the parties on this issue, I find it is proper for the state regulatory decisions to be construed as cites in the LPSC's reply brief and they are considered as such. Considering the additional state regulatory agency decisions with the ones previously in the record does not lead to a different result from my determination not to make the adjustment for "avoided" AFUDC advocated by the LPSC. Although I have considered the excerpts provided by the LPSC, as illustrated by the record in this case, including LPSC witness Kollen's confusion, the state decisions are not always clear on their face as to the actions the state is taking with regard to CWIP, AFUDC and rate of return without the explanation of an expert witness. Therefore, as noted in my decision, I give deference to and have relied upon the explanations and conclusions of Dr. Berry and Mr. Louiselle, experts who have participated in a number of state decisions on these issues in the relevant time-frame as witnesses and advisors for the APSC and the LPSC, respectively.

92. The excerpts which were not offered as exhibits simply do not demonstrate the LPSC's proposition in its reply brief (at 43-44) that the States of Arkansas or Mississippi gave the same or a lower return on equity when CWIP was not included in rate base. One could conclude from a review of the rate of return summary chart in the LPSC reply brief at page 44 that the states that did not include CWIP in rate base gave higher equity returns than the state (Louisiana) which did include CWIP in rate base. Louisiana, with CWIP in rate base, generally gave lower returns on equity at comparable periods of time. LC RB at 44 (Comparing 13.25 percent with 13.75 and 14.00 percent; 14.90 percent with 15.00 and 15.00 percent; 15.00 percent with 15.50 percent). Only in one situation listed in the chart did Arkansas give a lower return than Louisiana during what may be considered comparable periods of time. The excerpts, which of course are not the whole case, and which were cited, not in the initial briefs, but in the reply briefs, do not prove the position advocated by LPSC. Moreover, the material comparison, not answered by the LPSC's post-hearing chart and decision excerpts, is what a particular jurisdiction

would allow in rate of return with and without allowing CWIP in rate base. The LPSC's own decisions considered in the record of this case and discussed by the expert witnesses, clearly inform that increasing the rate of return is an alternative to allowing CWIP in rate base. Had the LPSC raised the decisions it now proffers during the hearing and sought the views of the witnesses on them, these decisions probably would have been explained further, perhaps to the detriment of the LPSC's position.

93. For the reasons stated above and as argued effectively by the parties opposing the adjustments, the proposal of the LPSC to reflect avoided AFUDC costs in the plant costs of ELI and EGSI is rejected.

B. Deregulated Asset Plan

94. Is it appropriate to consider and include imprudent production costs for purposes of consistently stating production costs among the EOCs? The APSC, the MPSC and Entergy argue that the costs associated with a Deregulated Asset Plan (DAP) should not be included in EGSI's production costs. AC-1 at 39 (Berry); MPS-1 at 38-39 (Larkin); and ETR-23 at 26-27 (Louiselle). Mr. Louiselle explains that the fact that EGSI has not written off these costs is irrelevant. ETR-23 at 26-27. Further, it is not disputed that retail regulators could structure prudence disallowances to maximize benefits to jurisdictional entities at the expense of non-jurisdictional entities. Tr. 1826-27 (Kollen).

95. The LPSC, on the other hand, does not want to exclude the costs of the EGSI River Bend DAP from production costs. LC-50 at 48-54 (Kollen). The DAP costs were considered imprudent by the LPSC and it disallowed them from rates. ETR-23 at 26. Arkansas points out that these are the only significant production cost prudence disallowance costs that are still reflected in the accounting records of Entergy. AC-1 at 39 (Berry). The APSC and the MPSC believe that it is not appropriate to include imprudent production costs to consistently state production costs among the EOCs. They point out that the decision by the LPSC in determining that certain production costs are imprudent and not proper for recovery from its own retail ratepayers is a strong indication that such costs should not be considered in production cost consistency calculations for the EOCs. A&MC IB at 43-44.

96. The LPSC explains that after a prudence disallowance relating to River Bend, the LPSC and EGSI's predecessor Gulf States Utilities Co. (GSU) agreed to an approach where GSU could establish a DAP. The LPSC agreed to provide a cost support for the DAP at 4.6 cents per kWh for the electricity produced from the unit. There was no write-off of investment costs on the GSU FERC books-of-account. Here, LPSC witness Kollen used the per book costs of River Bend for production cost purposes, while Entergy and other parties proposed reflecting only the lesser 4.6 cent retail cost. ETR-23 at 26-27 (Louiselle); LC IB at 68. The LPSC believes the DAP is no different than the retained shares of Grand Gulf of EAI and ELI. In the case of the retained shares, the LPSC

represents that the full cost is billed to EAI and ELI by SERI. Further, the LPSC says ELI pays 4.6 cents per kWh for the retained portion of Grand Gulf and EAI customers only pay "avoided costs," which is less than the 4.6 cents. LC IB at 68-69. Finally, the LPSC opines that FERC has already ruled on the propriety of including the per-books cost of River Bend in a production cost analysis. The LPSC says Entergy was successful in the Entergy-GSU merger approval case in contending that the full per-books costs should be included for wholesale purposes despite retail disallowances of River Bend costs. *Id* at 69; Tr. 4310-12 (Gallaher). *See Entergy Corp. and Gulf States Utilities Co*., 64 FERC ¶ 63,026 at 65,097 (1993), *aff'd* 65 FERC ¶ 61,332 (1993).

97. The cited merger approval case, Entergy official Gallaher's response to a comparison of the merger case with this case,[20] and the arguments of the LPSC do not persuade me to include costs proposed by the LPSC that are associated with the Deregulated Asset Plan for River Bend. With respect to Grand Gulf, the elimination of retail rate differences between jurisdictions placed all of the EOCs on an equal footing in terms of their comparative production costs because FERC mandated that the costs of Grand Gulf, unlike every other System resource, be shared by the EOCs in specifically defined amounts. River Bend was treated differently where costs have been disallowed as imprudent for one Operating Company and its ratepayers alone, and it would not be proper to reattach those costs to EGSI, inflating EGSI's production costs, and then shifting those costs to other EOCs. Arkansas and the other parties allied on this issue have convincingly demonstrated that imprudent production costs associated with the DAP should not be considered in production cost consistency calculations for the EOCs. Mr. Kollen's proposal to use the per book costs that include River Bend costs that were deemed imprudent by a regulatory body is rejected.

C. Grand Gulf Retained Shares

98. EAI and ELI receive bills from SERI each month for their respective shares of Grand Gulf costs, but both Operating Companies have entered into agreements with their regulators to absorb a portion of those costs. For those retained portions, EAI ratepayers are charged an "avoided cost" while ELI ratepayers are charged 4.6 cents per kWh. The LPSC notes correctly that Mr. Kollen's recommendation that the production costs associated with those retained shares continue to be reflected at their full cost, and not the lower cost authorized to be recovered from retail ratepayers, was not challenged by any party. LC IB at 67-68.

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[20] In response to a question from Mr. Fontham, Mr. Gallaher responded: "I think it's – it could be similar, but there are a lot of different aspects of the two cases …" Tr. 4312.

99. Regarding the retained shares of Grand Gulf by ELI and EAI, Mr. Louiselle for Entergy explains that a portion of the output and related costs of Grand Gulf purchased by these two Operating Companies is "retained" by each company and not reflected in its retail revenue requirement. Each company can sell that retained share in the wholesale market or sell it to retail customers at either a defined rate ($46/MWh for ELI) or a formula-based rate (EAI). ETR-23 at 37. In neither case was the retained share disallowed based on imprudence nor do the retained shares change the level of production costs incurred by each company. *Id*. at 38.

100. Entergy convincingly explains that with respect to Grand Gulf, the elimination of retail rate differences between the jurisdictions placed the EOCs on equal footing for their comparative production costs since FERC mandated that the costs of Grand Gulf, unlike every other System resource, be shared by the EOCs in specifically defined amounts. That is why all parties seem to agree with the LPSC that the full costs billed for Grand Gulf should be considered.

D. Texaco Refund

101. Entergy and others propose to include the effects of refunds made by Texaco to ELI in the early 1980s in order to reduce ELI's production costs. In 1982, a Compromise Settlement and Agreement was entered into by Texaco, ELI's major gas supplier, and ELI, providing ELI with over one billion dollars in cash in compensation for the release of an obligation to provide ELI with below market-price gas. ETR-23 at 47 (Louiselle); ETR IB at 40. Entergy represents that these proceeds were sent to ELI customers over the period 1982-1992, which was the remaining period of the Texaco gas supply contract. *Id*. Entergy's witness Louiselle reflected these proceeds on a pro rata basis as a credit to ELI's fuel costs in conjunction with the development of ELI's bus bar production costs over the 1985-1992 periods.

102. Entergy opines that the Texaco proceeds reflect a settlement of past damages as well as future damages over the contract life (ended in 1992), and that they are just as important to consider as the Waterford 3 investment dollars (*See* avoided AFUDC discussion *supra*.) that were expended over the period 1972-1985. ETR-74 (LPSC Special Order 22-82 – Compromise and Settlement Agreement); Tr. 5484-85 (Louiselle); Tr. 1776 (Kollen). Entergy concludes that for any analysis of production costs for the 1985-1992 period, the costs should be adjusted by a pro rata share of the Texaco proceeds. Entergy IB at 40-41. *See also* A&MC IB at 34-35 (showing the concurring position of the APSC and the MPSC).

103. The LPSC disagrees with the need for this adjustment for at least two reasons. First, historic comparisons based on 20-year-old production cost data should not form the basis for setting future rates. Second, the LPSC does not believe the facts support the adjustment even if the data is considered. LC RB at 50.

104. Mr. Louiselle conceded that the three Texaco payments in 1982, 1983 and 1984 were insufficient to pay past losses under the contract, but he stated that there were other benefits in the contract settlement for losses to be incurred in the future. Tr. 5486-87. The LPSC claims that higher future costs did not materialize and future damages were not incurred. LC RB at 50. No evidence of record establishes a contrary position.

105. The adjustment is not materially pertinent because it relates to a period that is too far into the past. Any benefits or credits regarding this Texaco contract ceased after the end of the contract in 1992. The LPSC Waterford 3 avoided AFUDC adjustment, rejected for other reasons, is distinguishable since the gross plant adjustment was not left in isolation but was reduced by the hypothetical accrued depreciation to try to bring the net plant cost up to the current period. The Waterford 3 avoided AFUDC adjustment, if it had been allowed, would still be having an affect on rates after 1992 and up to the present, unlike the Texaco adjustment.

106. In any event as noted above, the Texaco payments received through 1984 were insufficient to permit recovery of damages incurred through 1984. LC RB at 50. Therefore, they could not be considered as recovery of damages by ELI to credit and lower its production costs in the post-1985 FERC-mandated reallocation period. For these reasons and those listed in the brief of LPSC, there is no basis to adopt the Texaco adjustment.

E. Load Factor

107. For purposes of determining and comparing total production costs in cents per kWh units, fixed production costs must be converted from the demand basis on which they are presented of dollars per kW units to cents per kWh units by using the Operating Company's load factor. In this way variable production costs, which are stated on an actual energy basis in cents per kWh, can then be properly added to fixed production costs to compute total production costs in cents per kWh.

108. Each of Entergy's five Operating Companies, however, has different load factors. Load factor is a measure of the intensity of use that customers make of the capacity of a utility. S-1 at 38 (Sammon). Analysis of relative total production costs in cents per kWh requires that the relative differences in load factor among the Operating Companies be eliminated. Otherwise, as the LPSC observed, "[f]ailing to adjust for load factor makes the production costs of high load factor companies like ELI appear lower and the production costs of low load factor companies like EAI appear higher." LC RB at 39.

109. Every party in this case that addressed this issue agreed that load factor differences among the Operating Companies must be adjusted for most fixed costs (demand costs) on a 12-CP basis when they are unitized from kW to kWh. However, there is a dispute on how to account for nuclear demand costs. Entergy believes that fixed nuclear costs

should not be adjusted for load factor differences, while the LPSC would include nuclear fixed production costs in the 12-CP adjustment. ETR IB at 41; LC RB at 47.

110. Entergy's position is that the relatively high fixed costs and low fuel costs of nuclear plants set them apart from other generating units, and therefore "nuclear fixed costs should be treated differently than resources such as non-base load gas-fired facilities." ETR IB at 41. Similarly, the APSC and MPSC argue that "nuclear units are base load units constructed primarily to provide energy savings." A&MC IB at 35-36. Thus their position of not unitizing fixed nuclear investment would result in nuclear fixed costs being stated on an actual energy kWh basis, which is also known as average demand.

111. Although the Staff agrees that the LPSC's load factor adjustment proposal is generally consistent with how the Commission has traditionally allocated fixed costs, it still opposes including fixed nuclear costs in the adjustment. To support its position, the Staff cites *System Energy Resources*, Opinion No. 292-A, 42 FERC at 61,424-25, where "the Commission specifically determined to allocate nuclear demand costs on the basis of energy, energy (kWh) is appropriate to use to adjust nuclear capacity costs for load factor." S IB at 39.

112. In reply, the LPSC argues that the nuclear facilities on the Entergy System were not built only to supply energy but also to meet peak demand. The LPSC states that, initially in this case, "Entergy used the 12 CP allocator to load factor adjust all investment in all generation, including nuclear units. [Tr. 5478 (Louiselle)]. Mr. Louiselle utilized a 12 CP method for allocating capacity costs on the Entergy System in Docket ER82-483 [the System Agreement case decided by Judge Head] as well." LC RB at 48. In addition, according to the LPSC,

> Dr. Berry testified in the APSC decommissioning case that the 12 CP method should be used to allocate nuclear decommissioning costs. [Tr. 3575]. He further testified that as far as he knows there has never been a decision in Arkansas that allocated nuclear production costs on energy. [Tr. 3574]. Further, when the Grand Gulf costs were put in retail rates in Arkansas, the average and peak method was chosen by Dr. Berry and the APSC to allocate those costs. [Tr. 3568-69]. That method recognizes the dual cost causation of base load and intermediate units. [Tr. 3568]. Dr. Berry acknowledged that there is really very little difference between the average and peak method and the 12 CP method. [*Id*.].

Id. at 49. In rejoinder to the Staff's position, the LPSC contends that the Commission's decision should not control the load factor adjustment issue since it "never examined the theoretical basis for the allocation or its consistency with FERC precedent." *Id.*

113. In general, load factor refers to the ratio of the average load over a designated period to the peak load occurring in that period. Annual load factor, for example, is computed by multiplying the annual peak load of a customer by the number of hours in a year, and this result is then divided into the total energy the customer consumed over the year. *See* S-1 at 38 (Sammon).

114. With an example, Entergy witness Louiselle shows why load factor adjustments are necessary. *See* ETR-23 at 14. He assumed two companies had identical production facilities and costs, but one has a 60% load factor while the other has a 50% load factor:

Example Showing That Load Factor Affects Capital Costs When Stated In $/mWh			
Item	Company A	Company B	Total
Capital Costs	$150 Million	$150 Million	$300 Million
Peak Demand	1000 mW	1000 mW	2000 mW
mWh Sales	5,256,000*	4,380,000**	9,636,000
Load Factor	60%	50%	55%
mWh at Average Load Factor	4,818,000	4,818,000	9,636,000
Capital Costs/mWh:			
a) Per Actual mWh	$28.53	$34.25	$31.13
b) Per mWh at System Average Load Factor	$31.13	$31.13	$31.13

*Company A: 1000 mW x 8,760 hours/year x 60% = 5,256,000 mWh.
**Company B: 1000 mW x 8,760 hours/year x 50% = 4,380,000 mWh.

115. As the table illustrates, each company has identical capital costs of $150 million and both have the same peak demand (1000 mW). The difference is load factor. A 60% load factor for Company A results in energy sales of 5,256,000 mWh, and a 50% load factor of Company B results in 4,380,000 mWh. To correct for load factor differences, the parties adjusted each Operating Company's load factor to essentially put them on the same level as the Entergy System load factor. *See* Tr. 1306-07 (Baron). In Mr.

Louiselle's example, he essentially assigns a common load factor of 55% for both companies resulting in $31.13 per mWh for each.[21]

116. The Staff concedes that the LPSC's load factor adjustment proposal is generally consistent with how the Commission has traditionally allocated fixed costs. Nonetheless, it believes that *System Energy Resources* should control the issue. It is correct that the Commission allocated the fixed nuclear investment costs on the basis of average demand, which as noted above is an energy allocation. Contrary to the LPSC's criticism, the Commission stated expressly that it did so to reflect the fact that the nuclear power plants are operated to meet the base load demand on the system, that the fuel diversification of adding nuclear generation also was a goal, and that therefore the average demand allocation correctly reflects the energy use of nuclear plants. 42 FERC at 61,424-25 (citing 31 FERC at 61,651-53).

117. There is no one method of allocating the fixed nuclear costs that would perfectly mimic their multi-use cost-causation. *See* Tr. 3567-74 (Berry). The average and peak method used in the past by Dr. Berry in Arkansas State cases attempted to capture both the energy and demand cost causation factors, but as he testified the differences from 12-CP were not enough to matter. Tr. 3567-68 (Berry). Nor are the differences significant between a 12-CP allocation and the way Entergy allocates the fixed nuclear costs. Tr. 3573-74 (Berry). Given the Commission's direct precedential conclusion of this matter, combined with the fact that there is no strong support in this record to change that result,[22] I find that the continued use of an average energy allocation for fixed nuclear costs has not been shown to be unjust, unreasonable or unduly discriminatory or preferential.

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[21] Similarly, LPSC witness Baron explained that, "the fixed costs should be unitized for each Operating Company by calculating a kWh divisor using a common load factor, reflecting energy usage as if it were proportionate to each Company's 12 CP demand." LC-1 at 58.

[22] There is no evidence of a change in the use of nuclear plants to supply base load energy notwithstanding the fact that as with any large generating unit they also contribute to meeting peak demand. Moreover, the fact that the allocator to unitize fixed production demand costs is the 12-CP makes it relatively close to an average demand allocation. In the context of a different issue discussed later in this decision, regarding the MSS-1 Service Schedule to equalize excess reserve capacity among the Operating Companies, I explain the 12-CP methodology.

IV. REMEDIES PROPOSED BY THE LPSC

A. If Full Production Cost Equalization is adopted, what, if any, impact will there be on the level of costs subject to the jurisdiction of retail regulators, and what are the implications of that impact?

118. The LPSC argues that full production cost equalization will have no impact on the jurisdictional relationship between the FERC and the state/retail regulators. LC IB at 110. The LPSC states that Entergy's position, that full production cost equalization would unnecessarily intrude into the realm of state regulatory bodies, overly exaggerates the jurisdictional impact. What full production cost equalization will accomplish, the LPSC argues, is the elimination of discrimination among the Operating Companies on the Entergy System.

119. The LPSC's main reason for advocating full production cost equalization is that *all* production costs incurred by the Operating Companies are incurred for the system as a whole; there are no system generating resources that are dedicated specifically to serve any discrete and identifiable load of the Operating Companies. LC-8 at 17-20 (Kollen). However, the proposed change to full production cost equalization would not come without dramatic changes to the way that the Entergy System currently operates.

120. The LPSC argues that the transferring of costs does not automatically imply a loss of authority for state retail regulators. What full production cost equalization would do is recognized by the LPSC as follows:

> Full cost equalization would increase the amount of costs transferred pursuant to MSS-1, but only because it would replace a System that tolerates profound discrimination with one that transfers sufficient costs to eliminate the discrimination. These cost transfers constitute the real reason for the objections of Entergy and the APSC-MPSC. The larger cost transfers increase the effect, but not the extent, of FERC jurisdiction.

LC RB at 75. The LPSC argues that the DC Circuit's opinion in *Mississippi Industries* established the fact that FERC has jurisdiction over all capacity costs on the Entergy System. 808 F.2d at 1548-49, 1555-56, 1557. The LPSC also argues that in Opinion No. 292, the Commission made it clear that it had jurisdiction over all of the production costs on the Entergy System. 41 FERC at 61,615. State retail regulators still retain jurisdiction over the establishment of retail rates, which includes the situs production costs, distribution costs, customer service costs, and other costs. LC IB at 111. Therefore, the LPSC argues, the jurisdictional relationship between state and federal regulators is preserved if full production cost equalization is ordered, with the only effect being a change in the level of payments needed to eliminate the undue discrimination on the Entergy System.

121. But according to Entergy, the effect of replacing the status quo with full production equalization would be to federalize all System generation cost. Entergy states that Judge Head in a prior decision rejected the Staff proposal to equalize System base load production costs. Judge Head found as follows:

> The ordering of production cost equalization would dramatically affect the rate base in the States involved, to such an extent, for example, that approximately 75% of AP&L's rate base would be affected by production cost equalization. There is, therefore, a strong policy reason for not invading the State commission's authority to set retail rate by assuming Federal control over such a large portion of AP&L's rate base. . . . While the reasons favoring equalization are not unsubstantial, they are not so compelling that they justify the extensive intrusion into an area normally subject to regulation by the State commissions.

30 FERC ¶ 63,030 at 65,170.[23] Entergy points out that the Commission agreed with Judge Head that "the interests of the states involved in this case weighed heavily in favor of our decision *not* to adopt full production cost equalization." 32 FERC ¶ 61,425 at 61,952 (1985) (emphasis in original). Likewise, the D.C. Circuit agreed that ordering full production cost equalization would "represent a dramatic disruption of the System's historical operations and of the states' settled interests and expectations." *Mississippi Industries*, 808 F.2d at 1565 (vacated in part on other grounds).

122. Entergy discussed the ramifications of this so-called federal takeover. Federal jurisdiction over full equalization of production costs (which includes base load generation costs) would extend only to allocating those costs among the Operating

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[23] A different quote excerpted in Entergy's initial brief (ETR IB at 79) from Judge Head's decision at 30 FERC at 65,149 to support this same proposition was taken out of context, as it comes from an earlier section in the decision where Judge Head was summarizing the positions of the parties. However, as the quote I use above demonstrates, Judge Head did rule on the propriety of ordering full production cost equalization. Thus, contrary to the LPSC's argument (LC RB at 76-77) that Judge Head never made a ruling on the impact on retail regulation of ordering full production cost equalization, Judge Head fully examined the issue of full production cost equalization and made a ruling that, as I point out in the text, was supported later on by both the Commission and the D.C. Circuit.

Companies, but not on rate matters such as setting the rate of return on investment. This would lead to a state/FERC conflict as Entergy witness Louiselle described LPSC witness Baron's position:

> Even though the FERC now would have exclusive jurisdiction over all production costs, the LPSC and CNO proposal would not allow the FERC to actually exercise that jurisdiction for any purpose (setting cost of service, return, etc.) other than allocating costs among the Operating Companies. In effect, the LPSC and CNO want it both ways – FERC jurisdiction for some purposes but not for others.

ETR-23 at 79-80.

123. Entergy argues that Mr. Baron's testimony in fact supports the proposition that the states would continue to regulate the revenue requirements of the individual Entergy Companies under the LPSC's proposal:

> Under the LPSC's methodology, state regulatory commissions will continue to regulate the revenue requirements for individual Entergy Companies under their jurisdictions. The state commissions will continue to establish rates of return on investment and determine the reasonableness of the recovery of operating expenses and other ratemaking adjustments that are considered at the state level.

ETR IB at 79-80 (citing LC-1 at 64-65). As Entergy sees it, "the LPSC asks FERC to allocate *all* production costs, but asserts that the *allocation* has no pre-emptive effect whatsoever and the states have unfettered discretion to make findings respecting costs (e.g., rate of return) that conflict with the FERC's findings as to the very same costs." *Id.* at 80 (emphasis in original).

124. The APSC and the MPSC join Entergy in opposing the LPSC's full production cost equalization proposal. According to the APSC and the MPSC, retail regulators would lose jurisdiction over a great majority of production costs if total production costs are equalized. APSC witness Berry stated that on the average, state retail regulators would lose jurisdiction over 80% of their company's production costs with the LPSC's full production cost equalization proposal. AC-1 at 60. He pointed out that the

percentage of production costs lost by retail jurisdictions would be 80% for EAI, 67% for EGSI, 72% for ELI, 88% for EMI, and 93% for ENOI.[24] *Id.*

125. The APSC and the MPSC further argue that adoption of the LPSC's full production cost equalization proposal would "unnecessarily burden" state and federal regulators by forcing them to review other jurisdictions' imprudence decisions to prevent the subsidy of other state's ratepayers through the payment of imprudent costs. A&MC IB at 79. *See also* Tr. 1060-61 (Baron) (agreeing that the LPSC's proposal would have the effect of requiring such a review). According to the Arkansas and Mississippi Commissions, this would force the relitigation of the prudence of costs that were incurred decades earlier, and would further complicate the relationship among the various state and federal regulatory entities. Tr. 1117-19 (Baron) (agreeing that the states would have the ability to revisit prudence decisions made decades ago by other jurisdictions).[25]

126. Staff opposes the LPSC's full production cost equalization proposal as well. Staff agrees with the arguments of the APSC and the MPSC that full production cost equalization would encourage the intervention of state retail regulators in other states' proceedings, with the result of increasing regulatory conflict among Entergy and the various jurisdictions. S IB at 57-58.

127. After reviewing the arguments of the parties, I find that the implementation of the LPSC's full production cost equalization proposal would substantially affect the relationship between FERC and the various retail regulatory entities. This finding is not surprising when a comparison is made between the existing Entergy System Agreement and LPSC's proposed methodology. It may be true, for instance, that the allocation process among the Operating Companies would not be affected, since this process would continue to be under FERC jurisdiction. It is also correct that "allocation" would be done on the same factors under the present System Agreement and in full production cost equalization, i.e., the same responsibility ratios whether it be 12-CP, 4-CP, or some other allocation factor for fixed costs. But, this consistency in allocation factors is beside the point. What matters is the huge increase in costs that would be put into play outside of

[24] The APSC and the MPSC note their view that the LPSC's espousal of full production cost equalization before the Commission is ironic because it has vigorously opposed the formation of an Entergy Transco that would have the effect of removing transmission costs from the jurisdiction of state retail regulators. *See* AC-22 (LPSC Docket No. U-25965). *See also* AC-23 (Protest of the LPSC in *Cleco Power, LLC, et al.*, FERC Docket No. EL02-101-000).

[25] In passing, the APSC states that if full production cost equalization is adopted, it would be necessary to have a one-time true-up of nuclear decommissioning costs. The MPSC does not join in this argument and opposes such a true-up. A&MC IB at 79-80.

the jurisdiction presently available to the retail regulators. If I use his 2001 test year for illustrative purposes only,[26] LPSC witness Baron shows a substantial shift in costs to EAI and EMI ($321 million) from the other Operating Companies if full production cost equalization is adopted to eliminate discrimination entirely. *See* LC-3 and LC-5 (Baron Exhibits dealing with 2001 production cost data). *See also* LC-8 at 50 (Kollen).

128. Although retail ratemaking decisions would not determine the wholesale cost allocation process itself, the 2001 test year total production cost of service analysis sponsored by LPSC witness Kollen shows that the states would be able to transfer production costs to the other Operating Companies, since these costs would be added to the Entergy System costs and then allocated to the individual Operating Companies. For example, every dollar increase that the LPSC allows for fuel would be added to the total Entergy System costs and then passed on proportionately to all the Operating Companies, including ELI. See LC-12 (Kollen Exhibit dealing with 2001 production cost data). Mr. Kollen believes that all production costs for all Operating Companies should be combined since "the Commission already has determined that all production costs incurred by the Operating Companies are incurred for the system as a whole." LC-8 at 17. In essence, he believes that all production costs should be treated similar to the Grand Gulf costs, which were allocated on a system-wide basis by the Commission in Opinion No. 234. See LC-8 at 17-20.

129. The record also indicates that the adoption of full production cost equalization would result in retail regulators having less authority over the costs of the Operating Companies within their respective jurisdictions. This is to be expected since production costs comprise about 72% of the total costs of the Operating Companies. In short, under the LPSC's proposal, FERC would assume a much greater regulatory role over the Entergy System's production resources.

130. In *Middle South Energy, Inc.*, the Commission rejected a proposal for full production cost equalization on the then-MSU System. In doing so, the Commission held as follows:

> What our decision purports to do is to eliminate drastic rate disparities at the wholesale rate level which are associated with units used for the mutual benefit of all companies, and to do so in a manner which disturbs the historical operation of the System as little as possible, and which allows the individual companies to retain as fully as possible the benefits of units they have financed and constructed.

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[26] It should be noted that the LPSC treats some costs differently than this decision does.

32 FERC at 61,959. In doing so, the Commission noted that while it has the power to adopt full production cost equalization, it does not have to. It still holds true that while the Commission is charged with eliminating undue discrimination, it does not have to eliminate all forms of discrimination. As long as establishing rough production cost equalization with a percentage bandwidth remedy would eliminate undue discrimination on the Entergy System, then the more intrusive remedy of ordering full production cost equalization is not necessary.

B. As an alternative to Full Production Cost Equalization, should the LPSC's Base Load Reallocation proposal be adopted?

131. In his rebuttal testimony, LPSC witness Baron proposed full equalization of base load capacity if full equalization of all production capacity is not approved. This variation in the LPSC's position was in response to Entergy's claim that its Strategic Supply Resource Plan (SSRP) could address the production cost disparities among the Operating Companies. The LPSC argues that "if a plan that focuses on resources rather than costs is adopted, it should reallocate the costs and benefits of all the base load capacity." LC IB at 114. Furthermore, the LPSC argues that the base load equalization would be "less intrusive" than its proposal for full production cost equalization, since it only involves 36% of the capacity on the System. LC-27 at 63 (Baron).

132. Mr. Baron stated that his base load alternative would equalize the costs of nuclear, coal, and hydro capacity, including the Vidalia hydro project. He did not view Vidalia as a "true" base load unit, however, since it is not available for the entire year at the same capacity level, "so the FERC might wish to consider an allocation of the Vidalia costs between base load and situs (ELI), based on the proportion to which the lowest expected capacity value in any month of the year bears to the average capacity value." LC-27 at 63-64. Baron summarized his alternative plan as follows:

> The Base Load Cost Equalization Plan could be accomplished on a one-time basis, using recent values for 12 CP demand, subject to review perhaps every five years. This approach would "fix" the cost allocations for significant periods and avoid disruptions in ratemaking at the retail level. Thus, it would address a major objection to FPCE [full production cost equalization] raised by other parties, particularly Entergy.

Id. at 64.

133. But Entergy contends that the LPSC's base load proposal is insufficiently supported and compares it to the LPSC's full production cost equalization methodology:

> Like full production cost equalization, the LPSC's base load reallocation proposal constitutes a massive reallocation of sunk investment costs, contrary to historic system practices and Opinion No. 234. Like full production cost equalization, the base load proposal accomplishes this reallocation by reducing the costs of some Operating Companies, namely ELI and ENO, at the expense of other Companies, namely EAI and EMI. And like full production cost equalization, the LPSC's base load proposal achieves its objectives by reallocating past and current costs, regardless of which jurisdiction paid for those costs in the past, instead of by focusing on acquiring new resources through the SSRP. Indeed, by its very nature, the base load proposal seeks to undo prior Commission precedent regarding the allocation of costs associated with nuclear facilities, and thereby disrupts the very fabric upon which Order No. 234 was based.

ETR IB at 83-84. The LPSC's claim that its base load equalization plan would only affect 36% of the capacity on the System belies the fact that this figure translates into 80% of the System's revenue requirements related to fixed production costs. ETR-52 at 4-5 (Louiselle). Entergy also criticized the LPSC's inclusion of Vidalia in its base load equalization proposal, because Vidalia should not be considered a base load resource due to its inconsistent availability. ETR-52 at 7-8 (Louiselle). Entergy argues that the LPSC effectively admits that Vidalia is not a base load resource with its proposal to only count 64% of Vidalia's costs as base load. Tr. 308-12 (Baron). Because it does not constitute a "less intrusive" alternative to full production cost equalization and is contrary to established Commission precedent, Entergy urges that the LPSC's base load reallocation proposal be rejected.

134. Both the APSC and the MPSC join Entergy in opposition to the LPSC's base load reallocation proposal. They characterize the LPSC's proposal as being almost identical to the LPSC's full production cost equalization proposal, since base load units account for 93% of the System's net plant costs. AC-47 at 6 (Berry). When viewed in this manner, the APSC and the MPSC argue, the LPSC's base load equalization proposal has 93% of the effect of the LPSC's full production cost equalization proposal. *See id*. *See also* A&MC IB at 81. They also point out that the LPSC's proposal equalizes all future capacity purchases, which as the older oil and gas capacity is phased out, will have the effect of moving the System towards full production cost equalization under a different name. Tr. 1165-67 (Baron). Staff joins in the analysis of the LPSC's base load reallocation proposal, finding that it has just as much impact on the Operating Companies as the LPSC's full production cost equalization proposal. S IB at 58-59. Therefore, Entergy, the APSC and the MPSC, and Staff all recommend that the LPSC's base load reallocation proposal be rejected.

135. After reviewing the evidence presented regarding the LPSC's base load reallocation proposal, I find that it is too intrusive into the traditional domain of retail regulators. In its reply comments, the LPSC agrees that its base load equalization proposal is closely akin to its full equalization proposal in balancing costs, but adds that "given the disparities in production costs, a remedy that accomplishes rough equalization must consider a large portion of the System's production cost." LC RB at 77. However, just as with full production equalization, LPSC's base load proposal would result in the retail regulators having less authority over the costs of the Operating Company within their jurisdiction. But this is unnecessary since undue discriminatory effects can be eliminated with a percentage bandwidth remedy without resorting to a method that erodes the traditional, established authority of retail regulators. In short, LPSC's base load alternative plays second fiddle to its full production equalization methodology, and is also rejected.

C. If Full Production Cost Equalization is not adopted, the LPSC proposes modifying Service Schedules MSS-1 and MSS-3.

136. The LPSC has proposed that both Service Schedules MSS-1and MSS-3 of the existing System Agreement be modified if full production cost equalization is not adopted.[27] LC-1 at 69, 90 (Baron). According to the LPSC, these schedules need to be modified to eliminate discriminatory transfers:

> If the FERC decides to leave the current System Agreement in place, it should at least correct two tariff and implementation deficiencies that allocate costs inconsistently with cost causation. MSS-1 allocates the cost of "reserves" on a basis that does not drive the need for reserves and Entergy interprets MSS-3 to permit transferring "sunk" costs as the price of economy exchanges. Both of these practices are discriminatory and should be corrected.

LC IB at 115.

1. Service Schedule MSS-3

137. The current System Agreement calls for the dispatch of resources in the following manner:

> All of the System's capability and purchases are . . . dispatched in such a manner as to obtain the lowest

[27] Judge Head described Schedules MSS-1 and MSS-3. 30 FERC at 65,122-23.

> reasonable cost consistent with reliability constraints, such as maintaining the proper daily operating reserves, voltage control, stability, proper loading of facilities, and continuity of service to all customers. After selecting the appropriate resources needed to serve the single, integrated system, which selection occurs in real time, the System Agreement allocates the energy and the costs among the member Operating Companies on an hourly after-the-fact basis using Service Schedule MSS-3.

ETR-3 at 9-10 (Turner).

138. Service Schedule MSS-3 governs the exchange and pricing of energy among the Entergy Operating Companies. In particular, Section 30.03 of the System Agreement describes the allocation of energy from the supplying Company to the Exchange:

> 30.03 <u>Allocation of Energy</u>
> The energy from the lowest cost source available and scheduled as in Section 30.02 above shall be allocated on an hourly basis, in the order of the following priorities:
>
> (a) first to the loads of the Company having such sources available; . . .
>
> (b) second to supply the requirements of the other Companies' loads (Pool Energy).

ETR-2 at § 30.03. If an Operating Company's resources exceed its load in that hour, it "sells" into the Pool or Exchange. If its load exceeds its resources operating in that hour, it "buys" from the Exchange. ETR-23 at 106 (Louiselle).

139. For billing purposes, the resources of an Operating Company with resources in excess of load are stacked from highest to lowest in descending order, with the highest price units going into the Exchange. The reason for this billing arrangement is to allow the Operating Company to receive the benefit of the lowest cost energy from the resources that it owns. Tr. 712, 745-746 (Baron).

140. Entergy describes the billing formula in Schedule MSS-3 as follows:

> It should be noted that the "cost" of a generating unit used for stacking, as well as for reimbursing supplying companies under MSS-3, is the billing rate. The billing rate is defined under MSS-3 as the current estimated cost of fuel used, plus, for the fossil-fired generation, a variable O&M

> adder set by the FERC. The cost of fuel is determined for each generating unit by multiplying that unit's average annual heat rate for the prior year by the current estimated cost per British thermal unit ("Btu") of the fuel used. In the case of off-System purchases, the price of that energy that goes to the Exchange is the actual cost of purchases. Pursuant to MSS-3, an Operating Company's cost for Exchange Energy is the weighted average cost per kilowatt-hour ("kWh") of all energy allocated to the Exchange in that hour. ETR-3 at 12 (Turner); ETR-2 at §§ 30.04, 30.08, 30.09, 30.10; *see also* Tr. 715-16 (Baron).

ETR IB at 94, n.48.

141. According to LPSC witness Baron, however, revision of Schedule MSS-3 is necessary since the Entergy System is dispatched as a single electric utility without regard to generator ownership, and thus the intent of Schedule MSS-3 is to produce the lowest cost of energy to all the Operating Companies. Mr. Baron states that the pricing of Exchange or Pool Energy among Operating Companies should reflect this fact. LC-1 at 69-72 (Baron).

142. Specifically, the LPSC believes there are two similar problems with the operation of Schedule MSS-3. The LPSC contends that these problems occur because the cost of energy produced by the supplying Operating Company from generating units operating at minimum load and purchased power energy are often included in the cost of Pool Energy. *Id*. at 73. The LPSC proposes to limit the transfer price associated with purchase power energy and minimum load generating units at System incremental cost or System lambda.[28] *Id*. at 88.

143. As Mr. Baron testified, Entergy operates certain generating units at minimum load levels during some hours for reliability purposes. Each of the Operating Companies has units that operate at minimum to provide reliability benefits for itself and the System, and these units are not being dispatched based on their incremental energy cost. He contends that the problem occurs if an Operating Company, such as EAI, has excess generation during an hour. Schedule MSS-3 permits EAI to price its Exchange energy at the highest cost generation in its stack of resources, even though this highest cost generation includes inefficient units that are operating at minimum load, rather than the cost of the most

[28] "System lambda is the incremental cost associated with providing an additional mWh to the System and reflects the economic cost associated with energy use on the System during any hour." LC-1 at 86 (Baron).

economic available unit that is actually dispatched. *Id*. at 74-75. Mr. Baron summarizes his problem with generating units operating at minimum load as follows:

> Though each Entergy Operating Company has units operating at minimum, Companies that are "supplying" to the exchange (generally EAI and EMI) are able to transfer the cost of these minimum units to other Entergy Operating Companies through Service Schedule MSS-3. Although the incremental cost of energy generated to meet the System load during the hour may be relatively low, the exchange price could be high simply because of the stacking mechanism that includes units operating at minimum. An Operating Company purchasing from the exchange often could obtain energy through its own generation or through purchases at a lower cost, yet must purchase from the exchange. Although economic units are being dispatched to serve the buying Company's load, exchange energy is priced at the cost of the supplying Company's minimum load units. This problem occurs in a substantial number of hours during the year.

Id. at 75.

144. From the LPSC's viewpoint, a similar problem occurs with purchased power. Mr. Baron states that the incremental cost on the System is often lower than the cost of such purchases. When these purchases are scheduled by Entergy, they are allocated to each Operating Company on a load-responsibility basis. According to Mr. Baron, Operating Companies that supply energy to the Exchange by virtue of economic dispatch should not be permitted to transfer their allocated costs of scheduled purchases to other Operating Companies. He contends that, "in effect, a purchase designed to meet the reliability needs of each Operating Company is being transferred as if it were economy energy." *Id*. at 81.

145. To rectify both problems, Mr. Baron recommends that a cap be imposed within the Exchange at System lambda. If the energy of minimum load units enters the Exchange, the cost of such energy would be limited to actual cost or System lambda, whichever is lower. The difference between the capped price and the actual cost of energy would be borne by the supplying Operating Company. Similarly, Mr. Baron proposes to cap the transfer price through the Exchange at System lambda for purchase power costs. The supplying Operating Company would again be held only at costs associated with Exchange energy. *Id*. at 86-88.

146. The LPSC case on this issue is contrary to the objective of the System Agreement in which the reliability of service and economy of operation require that the energy

supply to the System be controlled from a centralized location. ETR-2 at § 3.07. Under the System Agreement, all of Entergy's resources serve the single, integrated System to obtain the lowest reasonable cost consistent with reliability constraints. ETR-3 at 10 (Turner).

147. Providing reliability of service such as voltage control and system stability is one of the most important responsibilities of the System Operator. At the same time, the System Operator provides for central economic dispatch to achieve the lowest possible cost for the System as a whole. Schedule MSS-3 properly treats minimum load generation the same as every other resource since, like every resource, it is committed and dispatched for the System as a whole and not just the Operating Company owning it. The same is true for purchased power – joint account purchases are made on behalf of all Operating Companies. Tr. 693 (Baron).

148. I find that reliability of service is provided by all of Entergy's resources, including minimum load generating units and purchased power. The System Operator uses all of these resources to ensure the operational integrity of the entire System, and thus all costs related to reliability are incurred on a total System basis.

149. Moreover, the current Schedule MSS-3 was approved by the Commission in Opinion No. 234 as part of the 1982 System Agreement. 31 FERC ¶ 61,305 at 61,660-62. On this record, no factual circumstances have been shown that would justify the modification to Schedule MSS-3. The fact that an Operating Company deemed to make "purchases" of MSS-3 energy in an hour also may have its own minimum run units to provide System reliability does not mean that its proportionate share of maintaining System reliability is skewed because it also shares (at a rate lower than the "seller's" actual incremental cost for the minimum unit) in the cost of other such units when it is deemed short of energy in a given one-hour period. As Entergy points out, "MSS-3 itself remedies any supposed unfairness in the charges for minimum run generation, as it prices that energy at *average* heat rates and thus the *same* price flows through the exchange whether a unit is operating at minimum, in load following mode, or at maximum capacity." ETR RB at 4.

150. While there may be other ways of designing the details of an MSS-3 type schedule, the LPSC has failed to establish that the current MSS-3 Schedule is unjust, unreasonable, and unduly preferential and discriminatory. The LPSC's proposal which in effect would assign System reliability costs more or less to individual Operating Companies is denied.

151. Failing to justify its proposal to change Schedule MSS-3, the LPSC argues that Entergy's application of MSS-3 violates the terms of the System Agreement. It states that Entergy's Schedule MSS-3 billing practices for minimum run and off-system power purchases do not reflect the economic dispatch of the System, which is to meet the load

requirement in the least-cost manner for all of the Operating Companies. LC IB at 124-125.

152. In particular, according to the LPSC, Section 30.03 of the System Agreement allows the allocation of Pool Energy to supply the requirements of the other Companies' loads. The LPSC argues that: "This provision, therefore, precludes the use of resources that are not responsive to load in the calculation of the exchange energy price. [Tr. 4003 (Baron)]. The minimum run units and the off-system purchases are not responsive to load. [Tr. 4034 (Baron)]" *Id*. at 125. In other words, the LPSC believes that billing under MSS-3 should follow dispatch. *Id*. at 124.

153. In response, Entergy argues that the mere fact that the LPSC believes that billing should follow dispatch does not prove that there has been any violation of the tariff. It states that the LPSC's own witness admitted during cross-examination that nothing in the System Agreement requires billing to follow dispatch:

> Q. Is there any requirement of which you're aware in the system agreement that requires that MSS-3 billing follow dispatch?
>
> A. Only to the extent of the general objectives and provisions that I've already discussed. There's no specific language that I am aware. And in fact, we're asking the Commission to modify the tariff to incorporate at least two elements of that billing follows dispatch.

Tr. 849-850 (Baron). Thus, as Entergy points out, Mr. Baron testified that the tariff needed to be modified in order to make this principle apply to the current Schedule MSS-3. ETR RB at 57-58.

154. I find that the LPSC has failed to prove that there has been a violation of Schedule MSS-3 of the Commission-approved System Agreement. Under the current System Agreement, all of Entergy's resources are dispatched in such a manner as to obtain the lowest reasonable cost consistent with reliability constraints. ETR-3 at 10 (Turner); *See* ETR-2, § 3.07. For billing purposes, Section 30.03 of the System Agreement allocates the energy from the cheapest source available, *including* costs related to any reliability constraints, to the loads of the Operating Company. Second, if its resources exceed its load in a given hour, the Operating Company sells into the Pool which again would *include* the costs related to any reliability constraints. Although the LPSC believes that minimum run units and System purchases should be excluded from the Exchange, Section 30.03 does not dictate the removal of these or any other resource from the Exchange.

2. Service Schedule MSS-1

155. The LPSC argues for a change in Service Schedule MSS-1 from the current load responsibility factor of 12 CP (Coincident Peak) to 4 CP if full production cost equalization is not adopted.[29] LC-27 at 126 (Baron); LC IB at 117. MSS-1 is designed to allocate costs for maintaining the reserve responsibility capacity among the Operating Companies. This is based on the share of an Operating Company's demand to and at the time of System peak demand.[30] The issue here is whether to measure this based on the rolling average of the monthly CPs for the twelve previous months (12 CP), or only on the average of the monthly CPs for the four summer months of June-September (4 CP).

156. LPSC witness Baron stated that the Entergy System is a summer peaking utility. He said that Entergy witness Turner testified in the Entergy Retail Competition Case that the Company uses a Monte Carlo analysis to determine the amount of capacity purchases or additions that must be made for the summer period based on a loss of load probability requirement. In recent years, the Entergy System has been short of capacity and has been required to purchase 2,000 to 3,000 megawatts annually to meet its summer peak. LC-1 at 90-92 (Baron).

157. Based on December 2001 data for the System, Mr. Baron compared the average 12-month average peak demand to the Entergy summer peak demand. He stated that the August peak was 21.6% higher than the average 12 CP demand, while the reserve margin for August was 5.9%.[31] He contended that "[t]his is clearly well below any reasonable

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[29] LPSC witness Baron had initially advocated a 1 CP methodology. LC-1 at 91. However, Staff witness Sammon stated that Mr. Baron's analysis in his direct case at most supports the use of a 4 CP summer allocator, and that a change would not be appropriate without the preparation of a reserve table. S-1 at 44-45. Subsequently, in response to Mr. Sammon's testimony, Mr. Baron prepared a reserve table which he states supports the 4 CP methodology. LC-27 at 125-126.

[30] "A 12 CP load is defined as the average of l2 monthly coincident peaks. These monthly peaks are established based on the time of the monthly peak demand of the Entergy System. Each Operating Company's monthly peak is then determined by the mW demand of the Operating Company at the time of the Entergy System peak during the month." LC-1 at 91, n.8 (Baron).

[31] The August 2001 peak for the Entergy System was 20,257 megawatts (mW). The 12 CP load was 16,655 mW. Thus, the August peak is 21.6% higher than the 12 CP demand ((20,257 mW - 16,655 mW)/16,655 mW = 21.6%)). Since the generating capacity owned and contracted for by the Entergy Operating Companies was

level of reserves and is another indication that the System has been short of substantial amounts of capacity during the summer months." *Id.* at 93. Mr. Baron presented a reserve table which he believes supports a 4 CP load responsibility factor. In his rebuttal testimony, Mr. Baron stated the following:

> In response to Mr. Sammon's suggestion, I have developed a chart (figure 14) that shows the Entergy System reserve margin by month for the 12-months ending November 2002. The chart shows the amount of monthly capability, exclusive of short-term purchases, compared to the monthly System peak demand. As can be seen from the chart, the System's reserves are relatively low during the four summer months of June through September.

LC-27 at 125-126.

158. According to Entergy, its System has been a summer peaking one throughout its history. Entergy argues that "[n]othing has changed to demonstrate that the use of a 12 CP allocator approved in prior System Agreement cases is no longer just and reasonable, *see, e.g.*, Tr. 5999-6000 (Sammon), and the LPSC's Brief does nothing to establish the contrary." ETR RB at 49.

159. Based on this record, however, Entergy incurs fixed production costs on a 4 CP basis. Entergy halfheartedly defended the current 12 CP method by stating that, unlike a 1 CP factor, a 12-month rolling average takes care of weather variations. ETR-23 at 116-117 (Louiselle). As noted above, the LPSC now is advocating the use of 4 CP to allocate MSS-1 costs, which results in averaging the four summer monthly peak loads.

160. More importantly, this issue is about cost-causation principles. Not only do the annual peak loads occur during the summer, but Entergy has been required to purchase 2,000 to 3,000 megawatts annually to meet its summer peak. In addition, as Mr. Baron showed, the reserve margin on the Entergy System is dramatically smaller during the summer of 2002 than during the other months of the year. LC-27 at 126 (Baron). *See also* LC-27C at 126, Figure 14 (presenting the reserve margin).

161. The evidence in support of using 4 CP is convincing. Entergy now incurs fixed production costs on a 4 CP basis, and the meaningful cost-causation measure of load responsibility for MSS-1 is the capacity contribution of the Operating Companies to meet

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approximately 21,446 mW and the peak demand in August was 20,257 mW, the result is a reserve margin of 5.9% ((21,446 mW -20,257 mW)/20,257 mW = 5.9%. *See* LC-1 at 93 (Baron).

that summer peak load. This is measured by comparing their monthly CP to the System peak *only* for June through September. I find that the LPSC has established that use of the 12 CP for MSS-1 is unjust, unreasonable, and unduly preferential and discriminatory, and that use of the 4 CP would be just and reasonable, and not unduly preferential or discriminatory. Therefore, based on cost incurrence, Entergy shall allocate fixed production costs in Schedule MSS-1 using a 4 CP responsibility ratio.

V. LPSC POST-HEARING MOTIONS

162. The LPSC's Motion to Determine that Entergy Corporation Improperly Withheld Documents and to Include them as a Late-Filed Exhibit, filed on December 22, 2003, is hereby denied. Under Commission Rule 716, a participant can request that a presiding officer or the Commission, for good cause, "reopen the evidentiary record in a proceeding for the purpose of taking additional evidence." 18 C.F.R. § 385.716 (2003). The good cause showing, under Commission precedent, requires the moving party to show "extraordinary circumstances" that go to the very heart of the case. *East Texas Electric Cooperative, Inc. v. Central and Southwest Services, Inc.*, 94 FERC ¶ 61,218, *reh'g denied*, 95 FERC ¶ 61,066 (2001).

163. In this case, the LPSC requested that I reopen the record to include the unredacted copy of the November 20, 2002 Minutes of the Entergy Operating Committee. Upon review of the memoranda submitted by the parties on this issue, I find that the LPSC has failed to meet the high burden of proof required to reopen the record in this proceeding.

164. Entergy provided the LPSC with a redacted copy of the minutes during the course of discovery in this proceeding as early as March 7, 2003. In another proceeding, Docket No. ER03-583, Entergy provided the LPSC with the unredacted minutes of the November 20th meeting shortly after May 12, 2003. Therefore, the LPSC had possession of the minutes before testimony was due in this case on June 6, 2003, and well before the conclusion of the hearing on August 22, 2003. Accordingly, I find that the LPSC's December 22 Motion is untimely, as the LPSC had ample opportunity to proffer this evidence before the record in this proceeding was closed at the conclusion of the hearing.

165. Moreover, I find that the information contained in the redacted portion of the November 20th minutes does not go to the very heart of the case in this proceeding. The redacted portions describe the results of a possible scenario that Entergy was considering in allocating energy supply in the system. It does not, as the LPSC alleges, show the Operating Committee's approval of the presented resource plan, as another resource plan was ultimately adopted by the Operating Committee. Furthermore, even taken in a light most favorable to the LPSC, the redacted information has no impact on the outcome reached in this Initial Decision. Accordingly, I deny the LPSC's Motion to Determine that Entergy Corporation Improperly Withheld Documents and to Include them as a Late-Filed Exhibit.

166. The LPSC's Motion to Take Official Notice of Filing with FERC, filed on November 6, 2003, also is hereby denied. Under Commission Rule 508(d), a "presiding officer may take official notice of any matter that may be judicially noticed by the courts of the United States, or of any matter about which the Commission, by reason of its functions, is expert." 18 C.F.R. § 385.508(d) (2003). Rule 201(b) of the Federal Rules of Evidence provides for the judicial notice of facts in U.S. courts. It reads, in pertinent part, "A judicially noticed fact must be one not subject to reasonable dispute in that it is either (1) generally known within the territorial jurisdiction of the trial court or (2) capable of accurate and ready determination by resort to sources whose accuracy cannot reasonably be questioned." Fed. R. Evid. 201(b). Therefore, to be judicially noticed, a fact must be "beyond reasonable controversy," where a "high degree of indisputability is the essential prerequisite." *Northeast Utilities Service Company*, 62 FERC ¶ 63,013 at 65,057 (1993) (quoting Advisory Committee Note to Fed. R. Evid. 201).

167. The LPSC asked that I take official notice of a letter that was sent by Entergy Corporation CEO J. Wayne Leonard to FERC Commissioner Nora Mead Brownell on September 24, 2003. The letter was part of the non-decisional file associated with FERC Dockets *Entergy Services, Inc*., ER03-583-000, *et al*. and *Entergy Services, Inc*., EL03-132-000. The letter discusses the bidding behavior of merchant generators. The LPSC wants to offer it for the fact that Entergy's letter advocates a different position than what Entergy advocated in this docket. Entergy disagrees, stating that the position taken by Mr. Leonard in the letter is exactly what Entergy advocated in the hearing in this docket: That merchants would decrease their bids in an increasingly competitive market.

168. After reviewing the memoranda of law filed by both parties in this matter, I find that the LPSC has failed to demonstrate that the letter can be officially noticed under Commission Rule 508(d) or under Rule 201(b) of the Federal Rules of Evidence. There is a dispute between the LPSC and Entergy as to whether the letter is inconsistent with Entergy's position at the hearing. Therefore, by the very nature of this dispute, the letter cannot be officially noticed because it does not meet the requirements of Federal Rule of Evidence 201(b) that demand that the issue be beyond controversy. Accordingly, the LPSC's Motion to Take Official Notice of Filing with FERC is denied.

169. Even if the LPSC's motion to take official notice of the letter is viewed as a claim that the letter is an inconsistent statement or a statement against interest by Entergy, the LPSC's allegation of the meaning and significance of what Entergy is saying is not something that can be determined on the papers, without witnesses. Moreover, even if taken in a light most favorable to the LPSC, the outcome reached in this Decision does not depend on an assumption or projection of the possible bidding behavior of merchant generators.

VI. ORDER

170. IT IS ORDERED, subject to review by the Commission on appeal or on its own motion, as provided in the Commission's Rules of Practice and Procedure, that Entergy Services, Inc. and its affiliates, as appropriate, shall make all filings necessary to effectuate the rulings made in this decision.

LAWRENCE BRENNER
PRESIDING ADMINISTRATIVE LAW JUDGE