In The
SUPREME COURT OF OHIO

Industrial Energy Users, Ohio, *et al.*,	:	Case No. 06-1594
	:	
	:	On appeal from the Public Utilities Commission of Ohio, Case No. 05-376-EL-UNC, *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Recover Costs Associated with the Ultimate Construction and Operation of an Integrated Gasification Combined Cycle Electric Generating Facility.*
Appellants,	:	
v.	:	
The Public Utilities Commission of Ohio,	:	
Appellee.	:	

MERIT BRIEF
SUBMITTED ON BEHALF OF APPELLEE, PUBLIC UTILITIES COMMISSION OF OHIO

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INTRODUCTION

There is a threat in Ohio. The threat is not immediate but it is serious and real. The viability of our electric distribution system and its ability to deliver the safety net of provider of last resort service to customers is in question. A distribution system needs more than wires to function; it needs energy and support services to allow the system to be charged and stable. This is the fundamental prerequisite to the delivery of energy, whether from a competitive supplier or from the utility itself, through that system to customers. The facilities needed to maintain an electrically stable distribution system are wearing out and challenged by environmental regulation. They will become inadequate.

There will, if nothing is done, come a time when the system will no longer function. This is the reality, the only question is when.

The Commission, as is its duty, has taken this problem in hand. It has authorized AEP to collect from customers a limited amount of money to be spent developing a plan, including economic analyses and consideration of alternative means, to address this long-term threat. This limited amount of money is to be credited against amounts the company was already authorized to collect as part of its Rate Stabilization Plan. When AEP presents the results of its analysis to the Commission in a future proceeding, the Commission will be in a position to determine most of the questions that worry the appellants-should a plant be built or should the company buy services in the market; if it should build, what sort of plant; should conditions be imposed on its use; should ratepayers bear some or all of the costs; how should these costs be borne? These are all questions for the future. Although much argument appears in the appellants' briefs on these topics, they are entirely premature. The Commission did a limited thing for a limited purpose.

In short, the Commission was faced with a real problem and only AEP's proposal to deal with it. Although the Commission requested other proposals, none was presented. All the Commission got was this multi-party appeal. A multi-party appeal will not keep the electric distribution system stable and functioning. That takes planning, exactly the planning that the Commission's order supports. The Commission does not have the luxury of waiting until the crisis hits. It needed to take limited, sensible action now. It did so and should be affirmed.

STATEMENT OF THE FACTS AND CASE

This appeal arises from the Commission's decision granting a cost recovery mechanism for the first phase of a three-phase Application filed March 18, 2005, by Columbus Southern Power Company (CSP) and Ohio Power Company (Ohio Power) (collectively AEP, AEP Companies or Companies) to provide for the design, construction and operation of a 629 [net] megawatt (MW) integrated gasification combined cycle (IGCC)[1] electric generation facility in Meigs County, Ohio. *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Recover Costs Associated with the Ultimate Construction and Operation of an Integrated Gasification Combined Cycle Electric Generating Facility*, Case No. 05-376-EL-UNC (hereinafter "*In re AEP*") (Opinion and Order at 3) (April 10, 2006), IEU-Ohio App. at 12, FE App. at 28, OEG App. at 31, OPAE Supp. at 17, OCC App. at 29.[2] The Companies' Application seeks to recover costs of the IGCC facility in three phases to continue throughout the commercial life of the facility. *Id.* But it is premature to discuss in this

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1 This is a new electric generating plant technology which is powered by coal. Although the plant uses coal, the coal is not burned as in a traditional plant. Rather the coal is converted into gas, primarily hydrogen, and the newly created gas is then used to fuel a combined cycle turbine. Although this gasification also creates carbon dioxide, the nature of the plant is such that this carbon dioxide may be removed prior to combustion relatively easily. A more detailed discussion of the technology can be found in the record at AEP Ex. No. 4 (Testimony of M. Mudd) at BHB/MJM Ex. 1 (White Paper), Sec. Supp. at 6-31.

2 Hereinafter, to improve the readability of this brief, corresponding references to appellants' appendices and/or supplements will be entered as footnotes. References to appellants' appendices and supplements are as follows: IEU-Ohio App. at ____ (Industrial Energy Users-Ohio); IEU-Ohio Supp. at ___; OEG App. at ___ (Ohio Energy Group); OEG Supp. at ___; OCC App. at ___ (Office of the Ohio Consumers' Counsel); OCC Supp. at ___; FE App. at ___ (FirstEnergy Solutions); OPAE Supp. at ___ (Ohio Partners for Affordable Energy).

appeal the second and third phases of the Application, which concern carrying costs on the cumulative investment in the generating facility and actual capital costs, respectively, because the Commission deferred its decision on these phases and costs to the next proceeding. *Id.* at 11-12, 23.[3]

Motions to intervene by Appellants Industrial Energy Users-Ohio (IEU), Ohio Energy Group (OEG), FirstEnergy Solutions Corporation (FirstSolutions), and Ohio Consumers' Counsel (OCC) were granted by the Commission below. *Id.* at 3-4.[4] The parties filed witness testimony in the case. *Id.* at 4.[5] Subsequently, local public hearings were held in Hilliard, Canton, and Pomeroy, Ohio. *Id.* Over 100 people attended the hearing in Pomeroy, where the plant is planned for construction. *Id.* Thirty people testified and twenty-six of them supported the project; including Senator Joyce Padgett and Representative Jimmy Stewart. *Id.*

An evidentiary hearing commenced on August 8, 2005, and continued each business day through August 16, 2005. *Id.* at 5.[6] Initial briefs were filed by the parties on September 20, 2005, and reply briefs were filed no later than October 11, 2005. *Id.* The Commission, by an Opinion and Order filed April 10, 2006, granted the Companies request for a cost recovery mechanism, as modified by the Commission, for the first

3 IEU-Ohio App. at 20-21, 32, FE App. at 36-37, 48, OEG App. at 39-40, 51, OPAE Supp. at 25-26, 37, OCC App. at 37-38, 49.

4 IEU-Ohio App. at 12-13, FE App. at 28-29, OEG App. at 31-32, OPAE Supp. at 17-18, OCC App. at 29-30.

5 IEU-Ohio App. at 13, FE App. at 29, OEG App. at 32, OPAE Supp. at 18, OCC App. at 30.

6 IEU-Ohio App. at 14, FE App. at 30, OEG App. at 33, OPAE Supp. at 19, OCC App. at 31.

phase of the IGCC project. The appellants filed applications for rehearing. The Commission, by Entry on Rehearing filed June 28, 2006, denied the appellants' applications for rehearing. Appellants timely filed their notices of appeal.

The Commission's approval of the Companies estimated cost of $23.7 million for the first phase will recover preconstruction costs, such as engineering and scoping study, through a 12-month bypassable generation surcharge applied to the Companies' standard service rate schedules approved in their rate stabilization plan proceeding (RSP) (*In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of a Post Market Development Period Rate Stabilization Pla*n, Case No. 04-169-EL-UNC (Opinion and Order) (January 26, 2005) (*RSP Order*)). *Id.* at 11.[7] The costs the Commission approved for the first phase began applying to customers' bills on July 1, 2006 for a 12-month period or until mid-2007. *In re AEP* (Finding and Order at 3) (June 28, 2006).[8] The IGCC facility benefits AEP's customers in the long-term with cheaper rates and reliable service, the local economy, the Ohio Coal Industry and clean coal technology.

The Application, the Commission concluded, is about providing distribution ancillary services to support the Companies distribution function. *In re AEP* (Opinion and Order 17) (April 10, 2006).[9] It is the Commission's obligation to assure reliable distri-

[7] IEU-Ohio App. at 20, FE App. at 36, OEG App. at 39, OPAE Supp. at 25, OCC App. at 37.

[8] IEU-Ohio App. at 77, OCC App. at 50-B.

[9] IEU-Ohio App. at 26, FE App. at 42, OEG App. at 45, OPAE Supp. at 31, OCC App. at 43.

bution service under R.C. 4928.02(A), and noncompetitive retail electric services are subject to the regulation of this Commission under R.C. 4928.05(A)(2). *Id.* The Commission held that Ancillary service is not listed as competitive under R.C. 4928.03; nor has it been declared competitive under R.C. 4928.04, by the Commission. *Id.* Since ancillary service meets neither test for being competitive under R.C. 4928.01(B), it is a noncompetitive retail electric service subject to the continuing regulation of the Commission under R.C. 4928.05(A).

It was clear to the Commission that ancillary services require generating plant. Accordingly, it found that SB 3 contemplated that an Electric Distribution Utility (EDU), like the AEP Companies, would provide ancillary service from generating plant at least until such time as the Commission found that the market conditions had developed sufficiently to allow a declaration of competitiveness. *In re AEP* (Opinion and Order at 18) (April 10, 2006).[10] The Commission could then relinquish its regulatory obligations as to retail ancillary service, under R.C. 4928.04(A), if there is effective competition and available alternatives. *Id.* The Commission found no blanket requirement in SB 3 that an EDU may not own generation assets and that R.C. 4928.17(E) confirms that there are circumstances in which ownership and control of generation assets is necessary to support the EDU's distribution function. *Id.* at 14.[11]

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10 IEU-Ohio App. at 27, FE App. at 43, OEG App. at 46, OPAE Supp. at 32, OCC App. at 44.

11 IEU-Ohio App. at 23, FE App. at 39, OEG App. at 42, OPAE Supp. at 28, OCC App. at 40.

The Commission recognized that Divisions (A) and (B) of R.C. 4928.14 require the Companies to fulfill provider of last resort (POLR) responsibilities after the Market Development Period (MDP) (*RSP Order* at 27).[12] *In re AEP* (Opinion and Order at 13) (April 10, 2006) .[13] The Commission specifically noted in the *RSP Order* that the Companies are the POLR to consumers who either fail to choose an alternative supplier or who choose to return to them after taking service from another generation supplier. *Id.* Consistent with that obligation to serve, the AEP Companies' responsibility extends to having sufficient capacity to meet unanticipated demand beyond ensuring capacity to serve non-switching or returning customers whose requirements may be readily predicted. *Id.*

The Commission, consistent with past precedent, found that an EDU's POLR responsibility imposes necessary costs that warrant compensation. *RSP Order* at 27;[14] *In re The Dayton Power and Light Co.*, Case No. 02-2779-EL-ATA (Opinion and Order at 28) (September 2, 2003);[15] *In re Ohio Edison Co., et al.*, Case No. 03-2144-EL-ATA (Opinion and Order at 23-24) (June 9, 2004), App. at 25-26; *In re AEP* (Opinion and Order at 13) (April 10, 2006).[16] The Commission further noted that the Ohio Supreme Court previously confirmed the EDU's POLR responsibility and the lawfulness of estab-

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12 IEU-Ohio App. at 245, OCC Supp. at 206.

13 IEU-Ohio App. at 22, FE App. at 38, OEG App. at 41, OPAE Supp. at 27, OCC App. at 39.

14 IEU-Ohio App. at 245, OCC Supp. at 206.

15 IEU-App. at 286.

16 IEU-Ohio App. at 22, OEG App. at 41, FE App. at 38, OPAE Supp. at 27, OCC App. at 39.

lishing a separate charge for recovering the costs of fulfilling that obligation in *Constellation NewEnergy, Inc. v. Pub. Util. Comm'n*, 104 Ohio St. 3d 530, 820 N.E.2d 885 (2004). *Id.* at 18.[17]

The Commission found that the statutory scheme of SB 3 does contemplate that the EDU would provide services from generating plant to provide "ancillary service" as it relates to POLR service. *Id.* The Commission reasoned that distribution reliability is a core concern and the EDU's POLR function is a distribution-related service. *Id.* The EDU is the only entity that can fill the POLR obligation, because it operates the distribution wires and these wires must remain charged for connected customers to receive service; the EDU must have capacity available ancillary to the provision of the distribution service. *Id.*

The Commission found that it has the authority to approve a mechanism that grants recovery of the costs of the IGCC plant. *Id.* This facility is necessary to allow the Companies to provide a firm supply of generation service to its Ohio customers under its market-based standard service offer. *Id.* at 3.[18]

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17 IEU-Ohio App. at 27, OEG App. at 46, FE App. at 43, OPAE Supp. at 32, OCC App. at 44.

18 IEU-Ohio at 12, OEG App. at 31, FE App. at 28, OPAE Supp. at 17, OCC App. at 29.

ARGUMENT

Proposition of Law No. I:

> **Rate increase provisions of Chapter 4909 Ohio Revised Code have no application to the provision of provider of last resort services through a rate stabilization plan which delivers market-based standard service offer but if they do, the Commission substantially complied with them. *Constellation NewEnergy, Inc. v. Pub. Util. Comm'n*, 104 Ohio St. 3d 530, 820 N.E.2d 885 (2004).**

Appellants devote significant time to arguing that the Commission did not comply with the rate increase provisions of chapter 4909.[19] Little point is served by this discussion. The Commission stated "The Commission agrees with AEP-Ohio that the ratemaking statutes are not applicable in this proceeding." *In re AEP* (Entry on Rehearing at ¶ 30 at 11) (June 28, 2006).[20] Thus, it is true that the Commission did not set out to comply with law that is not applicable.

Having recognized that the ratemaking statutes do not apply, does not mean that the parties were in some way deprived. The parties received notice that a rate increase was requested with all details of how that rate increase might work. The parties received ample opportunities for discovery which they utilized. The companies did not submit the Standard Filing Requirements[21] but there was no need for this information. The companies' rates could not include any amounts to address this provider of last resort ancillary service need because the problem is entirely new, being a creation of electric

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19 IEU Proposition I, FESOL Proposition II, OEG Propositions 3 and 4, OCC Propositions 2A and 2B.

20 OEG App. at 22, FE App. at 19, IEU-Ohio App. at 68, OCC App. at 20.

21 A group of filings outlining the company's books of account.

restructuring. The lack of a plan to address the ancillary service need was the problem the Commission identified. Therefore, the company books, although available to the parties through discovery, ultimately made no difference and so the lack of the Standard Filings has no significance. There was no document entitled "Staff Report of Investigation" but the Staff did appear and present its view of the company application through testimony and brief just as would have occurred had this been a rate increase case. A seven day hearing was held with cross-examination of multiple witnesses. Briefs and reply briefs were submitted.

All in all, the differences between this case and a rate increase proceeding are very difficult to identify and, ultimately, unimportant. If the Court should take the view that the rate case provisions of the Revised Code should have been followed more closely by the Commission, the order below should still be affirmed. Although the Commission believed, and believes, that the rate increase section of Chapter 4909 did not apply, the Commission nonetheless provided the parties with sufficient process that they were not harmed by the difference. The Commission should be found to have substantially complied with those requirements pursuant to R.C. 4905.09.

Proposition of Law No. II:

> **Chapter 4928 permits the Commission to authorize amounts for the provision of provider of last resort service outside a Chapter 4909 rate increase case. *Constellation NewEnergy, Inc. v. Pub. Util. Comm'n*, 104 Ohio St. 3d 530, 820 N.E.2d 885 (2004); *Consumers' Counsel v. Pub. Util. Comm'n*, 111 Ohio St. 3d 300, 856 N.E.2d 213 (2006).**

The various parties argue that the Commission's order below violates Chapter 4928 in different ways. These arguments will be refuted in the following sections. In fact Chapter 4928 is the source of the Commission's authority.

A. The Commission is not re-regulating generation.

Appellants spend much time arguing that the order below is some sort of effort to re-regulate the competitive regulation of electricity.[22] These arguments only underscore the Appellants failure to understand both the controlling law and the Commission's order.

1. Distribution ancillary service is subject to continuing regulation.

SB 3 fundamentally reformed the regulation of electricity in Ohio and changed the regulatory role of the Commission *vis-à-vis* generating facilities. It is quite correct, as the Commission noted, that the provision of retail electric generation service is a competitive matter no longer subject to rate regulation by the Commission. *In re AEP* (Opinion and Order at 17) (April 10, 2006);[23] Ohio Rev. Code Ann. § 4928.03 (Anderson 2006), App.

22 The arguments are found in OCC Proposition of Law 1A and 2F2, FESOL Proposition of Law IC and IA, OEG Proposition of Law 1, and OPAE Proposition of Law A.

23 IEU-Ohio App. at 26, OEG App. at 45, FE App. at 42, OPAE Supp. at 31, OCC App. at 43.

at 71. This is where the Appellants make their first fundamental error. They reason that, since retail electric generation service is no longer regulated by the Commission and retail electric generation service comes from power plants, the Commission no longer can have any legitimate regulatory interest in power plants. While it is true that power plants produce the electric energy which, when sold, is retail electric generation service, they also can provide another service, distribution ancillary services. This function of power plants remains subject to regulatory control by the Commission. Appellants simply do not acknowledge the reality that power plants can fulfill multiple roles, one regulated and another not. Thankfully, the General Assembly recognized that there are functions of power plants that need to continue to be subject to regulation and Commission oversight, at least for a period of time, even after the primary function of those power plants has been deregulated.

It is the Commission's obligation to assure reliable distribution service. Ohio Rev. Code Ann. § 4928.02(A) (Anderson 2006), App. at 70. To this end, non-competitive retail electric services remain subject to the regulation of this Commission. Ohio Rev. Code Ann. § 4928.05(A)(2) (Anderson 2006), App. at 72. Non-competitive retail electric services are defined as components of retail electric service which neither have been declared competitive by this Commission (and no services have been declared competitive) nor are declared competitive by statute. Statute declares retail electric generation, aggregation, power marketing, and power brokerage services to be competitive. Ohio Rev. Code Ann. § 4928.03 (Anderson 2006), App. at 71. Distribution ancillary service is not listed as competitive by statute. *Id.* Further, although it is included within the list of components which could be declared competitive by the Commission, it has not been declared competitive. Ohio Rev. Code Ann. § 4928.05(A) (Anderson 2006), App. at 72. Since distribution ancillary service meets neither test for being competitive, it is a non-competitive retail electric service subject to the continuing regulation of the Commission. Ohio Rev. Code Ann. § 4928.01(B) (Anderson 2006), App. at 70.

Thus, it is clear that distribution ancillary service is subject to regulatory control by the Commission. We must now understand what it is. Distribution ancillary services consist of all those background sorts of activities which are needed for the distribution system be functional and are defined as:

> "Ancillary service" means any function necessary to the provision of electric transmission or distribution service to a retail customer and includes, but is not limited to, scheduling, system control, and dispatch services; reactive supply from generation resources and voltage control service; reactive supply from transmission resources service; regulation service; frequency response service; energy imbalance service; operating reserve-spinning reserve service; operating reserve-supplemental reserve service; load following; back-up supply service; real-power loss replacement service; dynamic scheduling; system black start capability; and network stability service.

Ohio Rev. Code Ann. § 4928.01(A)(1) (Anderson 2006), App. at 66. While the intimate details of the constituent services might be complicated, it is quite obvious that "reactive supply from generation sources" requires a generation source. "Back-up supply service" had better have a power plant associated or there won't be any back-up supply. Without real power from a power plant there could be no "real-power loss replacement service". The Commission determined that these functions require generating plant and this is simply true. *In re AEP* (Opinion and Order at 18) (April 10, 2006).[24] It is obvious that the General Assembly preserved a regulatory role for the Commission as regards these limited functions associated with generating plant.

Some might suggest that, although the Commission retains regulatory control over some generation-related services, the utilities may not own the generating plant to supply these services. No such limitation exists. Utilities may continue to own generation facilities but if the companies choose to supply a competitive service, they must comply with a Commission-approved corporate separation plan. Ohio Rev. Code Ann. § 4928.17(A) (Anderson 2006), App. at 74. Lest there be any doubt that the General Assembly intended that utilities could retain ownership of, and even construct, generating plant the experience of CWIP is instructive.

CWIP, it will be remembered, allowed for rate recovery of partially constructed utility facilities. Ohio Rev. Code Ann. § 4909.15(A)(1) (Anderson 2006), App. at 62-64. Although the language of the section was general, CWIP essentially only applied to electric generating plant because such plants were the facilities with a long enough construction period to warrant the temporary, partial rate treatment available in CWIP. Among the many changes wrought by SB 3, R.C. 4909.15 was amended so as to eliminate the CWIP provision. This amendment might create the impression that the General Assembly meant that utilities were to get out of holding electric plant altogether over time. The General Assembly had no such intention. The amendment of R.C. 4909.15 to eliminate

24 IEU-Ohio App. at 27, OEG App. at 46, FE App. at 43, OPAE Supp. at 32, OCC App. at 44.

the CWIP provision was to go into effect January 1, 2001. Before this could happen, House Bill 384 was passed and signed into law, repealing the SB 3 amendment. *See*, Uncodified Law following Ohio Rev. Code Ann. § 4909.15 (Anderson 2006), App. at 62-66. Lest there be any doubt about the General Assembly's intention, the balance of HB 384 was concerned with coal tax credits and the makeup of the mining board. As is required by the Constitution, bills must relate to a single subject and the single subject of HB 384 appears to be coal use. This is consistent with the General Assembly's intention that, at least for limited purposes and in limited amounts,[25] coal-fired generating plant could be built by utilities even in the restructured environment created by SB 3. The General Assembly realized that it had unintentionally eliminated the CWIP provision that would aid the construction of the limited amounts of coal-fired generation that the legislature had always intended and the legislature rectified that.

Thus generation used for the provision of distribution ancillary service remains subject to the regulatory control of the Commission and a utility may own it.

2. The Commission's order only concerns distribution ancillary service.

As noted, the Appellants misunderstand the Commission's order. This misunderstanding is surprising as the Commission could not have been more clear. It stated:

> While Section 4928.03, Revised Code, states that retail electric generation service is competitive and, not subject to Commission regulation, this Application is not about regulating retail electric generation service, but about providing

[25] The General Assembly may have meant more than this but whether it did or not is not necessary for purposes of the current situation.

> the distribution ancillary services. These services are subject to Commission regulation, as being necessary to support the distribution function.

In re AEP (Opinion and Order at 17) (April 10, 2006).[26] The reason for the Commission's concern is obvious as well. It said:

> Distribution reliability is a core concern of the Commission and the EDU's POLR function is a distribution-related service...The EDU is the entity that operates the distribution wires and these wires must remain charged for connected customers to receive service; the EDU must have capacity available ancillary to the provision of distribution service.

Id. at 18.[27] It should be noted that distribution reliability is vital not only for the provision of POLR service but any service at all. Competitive suppliers also rely on a stable distribution system to deliver their product to consumers. A distribution system works for everyone or no one. The Commission's concern is to assure that this distribution system will work for all.

The Appellants complain that the company application was not about distribution ancillary service at all and not about the provision of distribution ancillary service to support the utilities' provider of last resort obligations. These objections are both wrong and irrelevant. As noted previously, the Commission determined that the application in this case is about providing distribution ancillary services. *Id.* at 17.[28] More fundamentally,

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26 IEU-Ohio App. at 26, OEG App. at 45, FE App. at 42, OPAE Supp. at 31, OCC App. at 43.

27 IEU-Ohio App. at 27, OEG App. at 46, FE App. at 43, OPAE Supp. at 32, OCC App. at 44.

28 IEU-Ohio App. at 26, OEG App. at 45, FE App. at 42, OPAE Supp. at 31, OCC App. at 43.

the utilities' intent in making the filing is of no consequence and does not control the Commission. Just as a pitcher and a batter have vastly different intent about the same pitch, the utility and the Commission may not have a meeting of minds about the significance of any given filing. Ultimately it is the intent of the Commission which is at issue in this appeal, not that of the utility.

The Commission's intent is plain. The Commission wants to support the long-term reliability of the distribution grid as it is charged to do. It provided this support by requiring the utility to investigate the means needed to provide this support, including the possibility of constructing a power plant, and providing that the utility could collect its costs for doing so through an existing mechanism. These are entirely legitimate actions and the Commission order should be affirmed.

B. The existing market-based Standard service offer is not affected.

Appellants argue[29] that the Commission's order illegally changes the companies' existing market-based standard service offer, which is provided through what is termed a rate stabilization plan. This is perfectly incorrect. The two fit together seamlessly. Seeing this will require a review of the rate stabilization plan in the earlier rate stabilization case and the Commission's order below.

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[29] The arguments are found in OPAE Proposition of Law B, OCC Proposition of Law 1C and 1D, OEG Proposition of Law 5, and FESOL Proposition of Law 1b.

1. The rate stabilization order both establishes a market-based standard service offer and allows adjustments.

AEP's rate stabilization plan is the means through which AEP provides the market-based standard service offer required under R.C. 4928.14. It provides that AEP will supply ratepayers with electricity at rates which increase over the next three years in low, defined steps. *RSP Order* at 9.[30] It also provides for an additional increase, after hearing, under defined circumstances. The Commission order provides:

> AEP's RSP allows generation rates to further increase, after a Commission hearing, for: (a) increased expenditures incurred through an affiliate pooling arrangement for complying with changes in laws/rules/regulations related to environmental requirements, security, taxes, and new generation-related regulatory requirements imposed by statute/rule/ regulation/administrative order/court order; or (b) customer load switches. . . . The additional generation adjustments are effectively capped at four percent.

RSP Order at 20.[31] Thus the Commission's earlier order always contemplated the possibility of additional increases during the three-year period of the plan.

2. The order below complies with the rate stabilization order.

Despite Appellants' arguments claiming a conflict,[32] it is apparent that the Commission's order below is entirely in sync with the earlier rate stabilization order. What the Commission ordered below was an increase to repay the utility for the costs to

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30 IEU-Ohio App. at 227, OCC Supp. at 188.

31 IEU-Ohio App. at 238, OCC Supp. at 199.

32 These may be found in IEU Proposition of Law II and OCC Proposition of Law 2D.

study an additional generation-related regulatory requirement, specifically how best to provide the generation-related ancillary distribution services. *In re AEP* (Opinion and Order at 20-21) (April 10, 2006).[33] The Commission imposed this requirement after hearing, just as indicated in the earlier rate stabilization plan approval order.

Appellants complain that the charge authorized by the Commission should not be a part of the market-based standard service offer because it is not related to the current cost of generation and is not, therefore, market-based. Appellants bite the hand that feeds them. Charging the IGCC investigation costs as the Commission has done only *serves to benefit customers*. These charges are a portion of the cost to provide provider of last resort service without doubt and could properly have been included in the provider of last resort charge. The Commission so found. *Id.* at 18.[34] If the Commission had chosen to include these amounts in AEP's uncapped provider of last resort charge, the utility would have been able to collect these amounts *plus a potential of 4% more generation costs*. Instead the Commission chose to include these amounts in that capped 4% generation increase amount. In this way the most the utility can collect is the 4% *less these investigation costs*. The only entity harmed by the Commission's inclusion of these costs in the 4% cap instead of the provider of last resort charge is the utility.

Appellants' objections have no merit. The costs authorized for collection by the Commission are part of the cost to meet the provider of last resort duty. *Id.* This Court

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33 IEU-Ohio App. at 29-30, OEG App. at 48-49, OPAE Supp. at 34-35, FE App. at 45-46, OCC App. at 46-47.

34 IEU-Ohio App. at 27, OEG App. at 46, OPAE Supp. at 32, FE App. at 43, OCC App. at 44.

has already considered and approved the collection of provider of last resort costs from ratepayers through a charge imposed outside the rate-setting process. *Constellation NewEnergy, Inc. v. Pub. Util. Comm'n,* 104 Ohio St. 3d 530, 820 N.E.2d 885 (2004). The Commission acted consistently with its earlier order and with this Court's *Constellation* decision and should be affirmed.

C. There is no violation of any corporate separation requirement as none applies.

Utilities that offer both competitive and non-competitive services must comply with a Commission-approved corporate separation plan. Ohio Rev. Code Ann. § 4928.17(A) (Anderson 2006), App. at 74. AEP has such a plan which grants AEP a waiver of any requirement to structurally separate their competitive from their non-competitive holdings. *In re AEP* (Opinion and Order at 17) (April 10, 2006).[35] Thus, even if the Commission decision below was concerned with an asset used to provide a competitive service, and the decision below is concerned neither with an asset nor with a competitive service, there is no violation of the corporate separation requirement.

More fundamentally, the corporate separation requirement does not apply. As has been noted extensively, the Commission decision below is concerned with the investigation of the appropriate way to provision a non-competitive item, specifically distribution ancillary service. *Id.*; *In re AEP* (Entry on Rehearing at 6-7) (June 28, 2006).[36] The

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35 IEU-Ohio App. at 26, OEG App. 45, OPAE Supp. at 31, FE App. at 42, OCC App. at 43.

36 IEU-Ohio App. at 63-64, OEG App. at 17-18, FE App. at 14-15, OCC App. at 15-16.

separation plan requirement exists to separate competitive from non-competitive functions, where that is needed. Ohio Rev. Code Ann. § 4928.17(A) (Anderson 2006), App. at 74. The statutory separation plan requirement has nothing whatever to do with somehow subdividing the utilities non-competitive activities. The separation plan requirement simply has no application to the case below. Arguments to the contrary[37] have no value and should be ignored.

Proposition of Law No. III:

A Commission order should be affirmed when it explains the reasoning used and is supported by facts. Ohio Rev. Code Ann. § 4903.09 (Anderson 2006), App. at 62.

It has been argued that the order below is not supported by facts and does not contain a rationale.[38] Neither claim is based in reality as will be shown in the following sections.

A. The Commission has explained its reasoning.

Although Appellants argue that the Commission order is so unclear as to violate R.C. 4903.09, the arguments are disingenuous. The Commission's reasoning is perfectly clear, the Appellants simply disagree with the conclusions.

The Commission first observes, quite correctly, that it has a statutory obligation to maintain distribution reliability pursuant to R.C. 4928.02(A). *In re AEP* (Opinion and

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37 OCC Proposition of Law 1(B).

38 These claims are found in IEU Propositions of Law III and V, FESOL Proposition of Law III, OEG Proposition of Law 2, OCC Propositions of Law 2E, 2F and 3, and OPAE Proposition C.

Order at 18) (April 10, 2006).[39] Indeed, the system collapses if the Commission fails in this duty. The Commission reasons that distribution ancillary services remain regulated because those are the functions that are required to support and assure the reliability of the distribution system. *Id.* Distribution reliability falls on the shoulders of the utility unavoidably and its provision requires generating plant. The Commission stated:

> Distribution reliability is a core concern of the Commission and the EDU's POLR function is a distribution-related service. The EDU is the only entity that can fill the POLR obligation. Neither a CRES provider nor a regional transmission organization (RTO), such as PJM can provide POLR service. RTO's have a role at the wholesale, not the retail level, to facilitate market transactions and indirectly promote reliability; but RTO's do not have direct responsibility to the customers of a particular EDU. Even though a CRES provider does have a retail relationship and direct responsibility to customers, the EDU still stands as the backup POLR provider and that standby duty is distinct from the CRES function of fulfilling day-to-day or minute-to-minute power requirements. The EDU is the entity that operates the distribution wires and these wires must remain charged for connected customers to receive service; the EDU must have capacity available ancillary to the provision of the distribution service.

Id. As the Commission noted:

> Adequate, reliable, safe, efficient, non-discriminatory, and reasonably priced electric service cannot be provided to consumers in Ohio unless there is a functioning distribution system. The Commission's decision in this case is about ensur-

[39] IEU-Ohio App. at 27, OEG App. at 46, OPAE Supp. at 32, FE App. at 43, OCC App. at 44.

> ing the long-term viability of the distribution system and adequate capacity for AEP's POLR obligation.

Id. at 21.[40] AEP has submitted a plan to do this. The Commission stated:

> The AEP application lays out a regulatory mechanism by which it might recover the costs of a coal-fired electric generating facility, to address the long-term reliability and security of energy supply for the POLR obligation.

Id. at 19.[41] AEP's plan was not detailed in its development and needed further analysis so that it could be assessed. The Commission provided the financial resources and guidelines for the company to follow to accomplish these goals. It said:

> The Commission concludes that AEP should economically justify its construction choices, its technology choices, its timing, its financing structure, and the various other matters that have been left open in the current application. The reasonable costs to develop that plan and supporting analyses should be recoverable from ratepayers as a proper cost of providing distribution service.

Id. 20-21.[42] The Commission continued to enumerate five specific kinds of analyses that AEP should provide to aid the Commission in its review of whether, what sort, and how a plant should be built. *Id.* at 21.[43]

Thus, the Commission's reasoning is obvious. The Commission has a duty to oversee distribution reliability. Only the distribution utility can accomplish this reliabil-

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40 IEU-Ohio App. at 30, OEG App. at 49, OPAE Supp. at 35, FE App. at 46, OCC App. at 47.

41 IEU-Ohio App. at 28, OEG App. at 47, OPAE Supp. at 33, FE App. at 44, OCC App. at 45.

42 IEU-Ohio App. at 29-30, OEG App. at 48-49, OPAE Supp. at 34-35, FE App. at 45-46, OCC App. at 46-47.

43 IEU-Ohio App. at 30, OEG App. at 49, OPAE Supp. at 35, FE App. at 46, OCC App. at 47.

ity and it needs access to generation. AEP has presented a plan which purports to provide for the reliability needed to support the system and allow the POLR function to be accomplished. The Commission has authorized the recovery of those costs needed to further develop and analyze this plan. The Commission's reasoning is clear and the order complies with R.C. 4903.09.

B. The record supports the need to take action to support reliability.

Just as the Commission's reasoning is clear, the record support for the need for the Commission to take steps today is also obvious.

AEP claims it needs to build new capacity to continue to meet its obligations to provide provider of last resort service to its customers in Ohio. *In re AEP* (Application at 1-2) (March 18, 2005).[44] The Commission shares AEP's concern and sees the generating system in Ohio, which provides both competitive retail electric service and ancillary distribution service, as threatened. The threat comes from two directions.

1. Obsolescence

There is substantial reason to be concerned about the obsolescence of the existing generation in Ohio. This obsolescence affects the two predominate kinds of plants in Ohio, pulverized coal and natural gas, differently. The fleet of pulverized coal plants in Ohio is simply old. The plants have an average age of 44 years and they are not being

44 IEU-Ohio Supp. at 1-2, OEG Supp. at 1-2, OPAE Supp. at 1-2, OCC Supp. at 1-2.

replaced. Staff Ex. 1 (Testimony of Kim Wissman) at 6.[45] No new pulverized coal plant has been built in 14 years and Ohio's coal-fired capacity is actually dropping. *Id.* at 5.[46] The plain reality is that these plants will wear out and no longer be available. The day that these plants will be worn out and decommissioned may be hastened by the need to invest in them to meet current environmental requirements. AEP estimates that it will need to spend $3.7 billion over the next five years to meet the current Clean Air Interstate Rule and the Clean Air Mercury Rule. *Id.* at 6.[47] Such huge investment needs hasten the day when the plants will simply be shut down. The problem with shutting down these plants is that there is no replacement.

For years, the demands of new growth and coal plant retirements have been countered with the construction of gas-fired capacity. Essentially all new construction in Ohio for more than a decade has been gas-fired. *Id.* at 5-6.[48] While this approach seemed the environmentally friendly at the time, it has lead to a large reliance on natural gas as a fuel source. *Id* at 5.[49] Natural gas has been shown to be less than reliable. Volatility of natural gas supplies and prices have already idled some gas-fired capacity, rendering it economically obsolete. Serious questions exist about the long-term supply of natural gas. *Id.* It may be that natural gas simply will not be available for electric generation purposes at some point in the future, rendering the plants technically obsolete.

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45 IEU-Ohio Supp. at 114.

46 IEU-Ohio Supp. at 113.

47 IEU-Ohio Supp. at 114.

48 IEU-Ohio Supp. at 113-114.

49 IEU-Ohio Supp. at 113.

In the long run, there is substantial reason to believe that the current capacity reserve will be reduced and, it appears that nothing is being done about this problem.

2. Environmental Risk

While it is apparent that there are significant risks to Ohio's generation currently, there is an even more dire possibility. Even if our old coal plants can be patched together for decades more, and even if we can afford to retrofit mercury and sulfur controls on them, and even if there is natural gas to burn, and even if we can afford the natural gas to burn, the largest risk remains. Judging from the level of interest both in the United States and beyond, it appears that some sort of carbon sequestration will be required over the life of generating plants. Europe already has a trading regime for carbon allowances, several U.S. states are considering carbon restriction measures, and many businesses are altering there operations to anticipate a carbon constrained environment. Staff Ex. 3 (Testimony of Klaus Lambeck.) at 5.[50] While it is uncertain when such limitations might be enforced, generating assets are very long lived (that is of course one of the problems here, our plants are very old) and it is a virtual certainty that restrictions will be imposed over the life of the assets.

All fossil generation, both pulverized coal and natural gas, are vulnerable to carbon emission limitations. Both produce large volumes of carbon dioxide. At this point there is no hedge for this risk. The vast majority of generation in the Midwest, and the

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[50] IEU-Ohio Supp. at 126.

country generally, is fossil-fueled. Staff Ex. 1 (Testimony of Kim Wissman) at 4-5.[51] Thus there is no practical way to buy a hedge from any other supplier. All other suppliers are in the same position. Their plants produce carbon dioxide as well. The only practical hedge against this large risk is to build a new facility which anticipates carbon sequestration. Staff Ex. 3 (Testimony of Klaus Lambeck) at 4.[52]

An IGCC as suggested by AEP is one such facility which can relatively easily be altered to allow for the capture and disposition of carbon dioxide. This is not magic. The IGCC facility allows the removal of Carbon Dioxide before the synthetic gas is burned with air. *See*, AEP Ex. No. 4 (Testimony of M. Mudd) at BHB/MJM Ex. 1 (White Paper), Sec. Supp. at 6-31. The removal from the relatively small volume of fuel before it is burned is easier than removal from the smokestack after combustion.

It is largely agreed among the expert witnesses in this case that the key advantage offered by the IGCC technology is its potential to sequester carbon as part of the gasification process in order to virtually eliminate the substantial carbon dioxide emissions normally associated with a coal plant; the debate is whether it is cost-effective. Within the time frame for decision in this case, the Commission will not know for certain whether carbon sequestration regulations will be passed during the operational life of the plant (or what the content and timing of such requirements may be). But all of the expert witnesses in this case either opined that carbon sequestration regulations would likely be passed within the life of the plant or simply did not offer an opinion as to whether such

51 IEU-Ohio Supp. at 112-113.

52 IEU-Ohio Supp. at 125.

regulations would be passed. Staff Ex. 3 (Testimony of K. Lambeck) at 4-5;[53] Staff Ex. 1 (Testimony of K. Wissman) at 7-9;[54] AEP Ex. 4 (Testimony of M. Mudd), BHB/MJM Ex. 1 (White Paper) at 19, Sec. Supp. at 26. OEG Ex. 10 (Testimony of K. Higgins) at 20-21 (refers to "uncertainties concerning future environmental requirements" and says that there will be a "clear economic winner" depending on what happens but offers no opinion as to prospects of carbon capture regulations), Sec. Supp. at 33-34. No expert witness stated a belief that carbon sequestration regulations would not be passed during the life of the plant.

C. Newly constructed plants must be environmentally sound.

The record shows that the existing fleet of plant is in great danger. The coal-fired units are simply wearing out and may either need to be closed or have very large investments to remain operating when much anticipated carbon control legislation is enacted. There is no ability to purchase existing capacity to hedge this risk as all generation in the region is similarly positioned. Staff Ex. 1 (Testimony of K. Wissman.) at 5, 6-7.[55] Only construction of a generating plant with the potential to capture carbon allows for hedging of this risk. Staff Ex. 3 (Testimony of K. Lambeck) at 4.[56] The generating supply has shifted towards gas-fired facilities but the fuel costs for many of these plants are prohibitive currently and gas may simply not be available in the future while coal is available in

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53 IEU-Ohio Supp. at 125-126.

54 IEU-Ohio Supp. at 115-117.

55 IEU-Ohio Supp. at 113, 114-115.

56 IEU-Ohio Supp. at 125.

tremendous quantities. All these factors conspire to indicate that an environmentally sound plant needs to be constructed using coal as its fuel. Staff Ex. 1 (Testimony of K. Wissman) at 6-7.[57] While this may not be the ultimate decision, AEP has not yet submitted its analysis addressing these questions, the situation as described here points in that direction. *In re AEP* (Opinion and Order at 20-21) (April 10, 2005).[58]

IGCC may not be the answer. For example, there are other, non-IGCC technologies which anticipate removal of carbon dioxide. Staff Ex. 3 (Testimony of K. Lambeck) at 3-4.[59] AEP must analyze these in its next filing. *In re AEP* (Opinion and Order at 20-21) (April 10, 2006).[60]

D. The order addresses a real problem in a reasonable way.

Thus, The Commission has identified a real problem. Age and environmental regulation are conspiring to strangle our generating system. While the Commission is not charged to tend the well-being of the entirety of the generating system, it is charged to assure there is sufficient reliability to maintain the distribution system integrity so as to allow transactions, including fulfilling the POLR responsibility, to occur. To address this limited concern, the Commission has done a limited thing. It has ordered AEP to develop a plan to address this concern and to justify that plan. Further, the Commission has

57 IEU-Ohio Supp. at 114-115.

58 IEU-Ohio App. at 29-30, OEG App. at 48-49, FE App. at 45-46, OPAE Supp. at 34-35, OCC App. at 46-47.

59 IEU-Ohio Supp. at 124-125.

60 IEU-Ohio App. at 29-30, OEG App. at 48-49, FE App. at 45-46, OPAE Supp. at 34-35, OCC App. at 46-47.

allowed recovery of the funds needed to address this concern. These actions are reasonable, necessary, and are appropriately limited to the scale of the problem and the scope of the Commission's authority. The Commission's order should be affirmed.

Proposition of Law No. IV:

IEU-Ohio's requested relief is prohibited by *Keco. Keco Industries, Inc. v. Cincinnati & Suburban Bell Tel. Co.*, 166 Ohio St. 254 (1957).

IEU-Ohio requests the Court to make a case-specific exception to the *Keco* principle in this case in lieu of seeking an available remedy to stay the enforcement of the Commission's decision. *Keco Industries, Inc. v. Cincinnati & Suburban Bell Tel. Co.*, 166 Ohio St. 254 (1957). The *Keco* principle concerns the treatment of unjust enrichment and holds that errors made by the Commission do not create an opportunity for restitution by means of retroactive adjustment to rates. *Id.*

Under R.C. 4903.16, IEU-Ohio could have applied for a stay of the Commission's order below. If the Court had chosen to grant this unfounded request, and IEU-Ohio provided the undertaking that the Court set, it would have avoided the effect of the Commission's June 28, 2006, decision. But, instead, IEU-Ohio attempts to shortcut the rules and, in the process, requests this Court to carve out an exception to a principle that has been on the books without any exceptions being carved from it for fifty years. The Court should decline IEU-Ohio's proposal, because it circumvents the established remedy available for this requested relief and shifts the burden onto the Court to create a remedy in its place by diluting the *Keco* principle. The facts and law of this case are not worthy of IEU-Ohio's proposed new precedent.

Starting with the law, the ratemaking statutes in R.C. Chapter 4909 have no applicability in this case, which is IEU-Ohio's entire argument for its requested relief. The proceeding below concerned distribution ancillary services, which are non-competitive retail electric services that are subject to regulation by the Commission. AEP's POLR function is a distribution-related service. There is no legal prohibition under R.C. Chapter 4928 precluding AEP from owning and operating a generating plant to provide ancillary service to meet its POLR obligations, including unanticipated demand.

IEU-Ohio also recites part of the Commission's entry on rehearing in support of its proposition that if its appeal succeeds and the case gets remanded the Court should retroactively adjust rates by creating a case-specific exception to *Keco*. *In re AEP* (Entry on Rehearing at 11) (June 28, 2006);[61] *see also In re AEP* (Finding and Order at 2) (June 28, 2006).[62] The Commission's decision on Phase I of AEP's Application is both reasonable and lawful, and the Commission's language cannot be reasonably construed to support an exception to *Keco* on a potential remand. In its entry on rehearing, the Commission set terms and conditions for Phase I of the project on AEP. These terms and conditions address prospective factual developments involving the use of IGCC engineering and technology, not retroactive legal interpretation and application of R.C. Chapter 4928. The conditions and terms are AEP must use the funds collected for expenditures associated with items utilized at this site for this project. Otherwise, AEP will have to refund the ratepayers with interest.

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61 IEU-Ohio App. at 68, OEG App. at 22, FE App. at 19, OCC App. at 20.

62 IEU-Ohio App. at 76, OCC App. at 50-A.

In addition to discharging its duty in ensuring a long-term plan for the availability to AEP customers of adequate, reliable, and reasonably priced retail electric service, the Commission imposed these terms and conditions on AEP to avoid a potential subsidy to another state like West Virginia or Kentucky. The Commission is ensuring that AEP will begin construction of this proposed facility within five years of it entry. This condition makes it difficult for AEP to be able to transfer elements of design and engineering for the construction of a similar plant in a neighboring coal-rich state that could use the same technology. The prospect of this occurring is speculative at best. In contrast, the Commission's authority to increase generation rates under AEP's RSP, which establishes a market-based standard service offer as required under R.C. 4928.14 and allows adjustments after a Commission hearing, to address the problem of AEP's aging generation fleet is not speculative, but instead, real. *RSP Order* at 11.[63]

It is IEU-Ohio that is attempting to invent new law and procedure, not the Commission. IEU-Ohio had an adequate remedy at law to stop the Phase I Tariff from taking effect and it didn't utilize that law. Now it wants this Court to make new law, which would give IEU-Ohio the same desired relief, but retroactively. The difference now is IEU-Ohio must first win its appeal on an increased rate procedure argument that fundamentally misunderstands the Commission's authority over distribution ancillary services and the necessity to ensure the reliability of the distribution system. The Commission had authority to approve the preconstruction costs associated with the IGCC

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63 IEU-Ohio App. at 229, OCC Supp. at 190.

project. *Keco* does apply to this case and IEU-Ohio failed to provide any good reason to modify *Keco* now.

CONCLUSION

The Commission must assure the availability to consumers of adequate, reliable and efficient retail electric service. A viable, stable distribution network is needed to allow electric service to be delivered to consumers whether those consumers source their power from the distribution company, under its provider of last resort obligation, or from a competitive supplier. Serious, long-term threats to the viability of the distribution system exist, which would, if unaddressed, destabilize that distribution system. The Commission has addressed these threats in a sensible, moderate fashion. It has directed American Electric Power to develop a plan which will consider and address these concerns in a cost-effective manner and it has provided cost recovery for expenses necessary to do this analysis. What action may be taken after a review of this analysis cannot be determined now. Whether a plant will be built, what sort of plant might be built, when a plant might be built, how a plant would be financed, all these and many more are questions for another day. The only question for today is whether the Commission should be permitted to continue to do its job, assuring the reliable distribution system that we all rely on. It is in all of our interest for the Commission to take steps to shore up the distribution system. The Commission should be affirmed.

Respectfully submitted,

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PROOF OF SERVICE

I hereby certify that a true copy of the foregoing **Merit Brief** submitted on behalf of appellee, the Public Utilities Commission of Ohio, was served by regular U.S. mail, postage prepaid, or hand-delivered, upon the following parties of record, this 22nd day of December, 2006.

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APPENDIX

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BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Applications of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Continue and Modify Certain Regulatory Accounting Practices and Procedures, for Tariff Approvals and to Establish Rates and Other Charges Including Regulatory Transition Charges Following the Market Development Period.	)	Case No. 03-2144-EL-ATA

OPINION AND ORDER

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The Commission, coming now to consider the application, testimony, and other evidence presented in this proceeding, hereby issues its opinion and order.

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Ohio Consumers' Counsel, by Mr. Eric P. Stevens, Ms. Kimberly W. Bojko and Mr. Jeffrey L. Small, Assistant Consumers' Counsels, Office of Consumers' Counsel, 10 West Broad Street, Suite 1800, Columbus, Ohio 43215, on behalf of residential utility consumers of FirstEnergy Corp. operating utilities.

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Vorys, Sáter, Seymour & Pease LLP, by Mr. M. Howard Petricoff, Mr. W. Jonathan Airey, and Mr. William S. Newcomb, 52 East Gay Street, PO Box 1008, Columbus, Ohio 43215, on behalf of Constellation NewEnergy, Inc.; Reliant Resources, Inc.; Mid-American Energy; Strategic Energy, LLC; and Constellation Power Sources, Inc.

McNees, Wallace & Nurick, by Mr. Samuel C. Randazzo and Ms. Lisa M. Gatchell, 21 East State Street, 17th Floor, Columbus, Ohio 43215, on behalf of Industrial Energy Users-Ohio.

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Mr. William Sigli, City of Cleveland Law Department, 601 Lakeside Avenue, Cleveland, Ohio 44114, on behalf of the City of Cleveland.

Mr. Kerry Bruce and Ms. Leslie A. Kovacik, City of Toledo, Department of Law, One Government Center, Suite 2250, Toledo, Ohio 43604, and Lance Keiffer, Asst.

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Mr. Craig I. Smith, 2824 Coventry Road, Cleveland, Ohio 44120, on behalf of Cargill, Inc.

Ms. Evelyn R. Robinson, Green Mountain Energy Company, 5450 Frantz Road, Suite 240, Dublin, Ohio 43016, and Mr. Bruce J. Weston, 169 W. Hubbard Avenue, Columbus, Ohio 43215, on behalf of Green Mountain Energy Company.

Bricker and Eckler LLP, by Ms. Sally Bloomfield, 100 South Third Street, Columbus, Ohio 43215, on behalf of the Ohio Manufacturers' Association.

Chester, Willcox & Saxbe, LLP, by Mr. John W. Bentine and Mr. Bobby Singh, 65 East State Street, Suite 1000, Columbus, Ohio 43215-4213, on behalf of WPS Energy Services, Inc. and the City of Cleveland.

Bricker & Eckler LLP, by Mr. Glenn S. Krassen, 1375 East Ninth Street, Suite 1500, Cleveland, Ohio 44114-1718, on behalf of Northeast Ohio Public Energy Council.

Mr. William Ondrey Gruber, 2714 Leighton Road, Shaker Heights, Ohio 44120, on behalf of Citizen Power, Inc.

Boehm, Kurtz & Lowry, by Mr. David Boehm and Mr. Michael L. Kurtz, 36 East Seventh Street, Suite 2110, Cincinnati, Ohio 45202, on behalf of Ohio Energy Group and Kroger Company.

I. HISTORY OF THE PROCEEDINGS

On June 22, 1999, the Ohio General Assembly passed legislation[1] requiring the restructuring of the electric utility industry and providing for retail competition with regard to the generation component of electric service (Amended substitute Senate Bill No. 3 of the 123rd General Assembly, referred to as SB 3). Pursuant to SB 3, on July 19, 2000, the Commission issued an opinion and order approving and modifying a stipulation and recommendation with regard to the electric transition plan (ETP) of FirstEnergy Corp. on behalf of The Cleveland Electric Illuminating Company, The Toledo Edison Company, and Ohio Edison Company (Applicants or FirstEnergy).[2] In its ETP opinion, the Commission, among other things, allowed FirstEnergy a market development period (MDP) ending December 31, 2005, in accordance with Section 4928.40, Revised Code, and calculated the regulatory transition charges (RTC) to not extend beyond December 31, 2006, for Ohio Edison Company (OE), June 30, 2007, for Toledo Edison Company (TE), and December 31, 2008, for the Cleveland Electric

1 Amended Substitute Senate Bill No. 3 of the 123rd General Assembly.

2 *In the Matter of the Application of the FirstEnergy Corp. on behalf of Ohio Edison Company, The Cleveland Electric Illuminating Company, and Toledo Edison Company for Approval of their Transition Plans for Authorization to Collect Transition Revenues*, Case No. 99-1212-EL-ETP, Opinion and Order.

Illuminating Company (CEI) except for certain adjustments due to economic conditions. In addition, pursuant to Section 4928.39, Revised Code, the Commission determined the total allowable transition costs for CEI, TE, and OE (hereinafter referred to collectively as Operating Companies). In the ETP opinion, the Commission also required FirstEnergy to take a variety of listed actions related to transmission issues. During that MDP, the Commission anticipated that competition would develop, to the level described by the General Assembly in SB 3.

On October 21, 2003, FirstEnergy filed an application in Case No. 03-2144-EL-ATA for authority to continue and modify certain regulatory accounting practices and procedures, for tariff approvals, and to establish regulatory transition charges following the MDP. The application gave the Commission two options for establishing the price that customers will pay for generation service following the end of the MDP: a Competitive Bid Option and a Rate Stabilization Plan (RSP or Plan). The RSP was offered by the Operating Companies in response to the Commission's September 23, 2003 Entry in Case No. 03-1461-EL-UNC (September 23 Entry), in which the Commission requested that the Applicants develop and file a plan for 2005 and beyond that balances three objectives: (1) rate certainty, (2) financial stability for the Operating Companies, and (3) the further development of competitive markets. In addition to FirstEnergy's and the Commission staff's (Staff) participation in this proceeding, intervention was granted to the following parties:

> Ohio Consumers' Counsel (OCC); Dominion Retail Inc. (Dominion); Green Mountain Energy Company (GM); MidAmerican Energy Company, Strategic Energy LLC, and Constellation NewEnergy, Inc. (Ohio Marketers Group or OMG); WPS Energy Services (WPS); City of Cleveland (Cleveland); The Neighborhood Environmental Coalition, The Empowerment Center of Greater Cleveland, Consumers for Fair Utility Rates, and Citizen Power, Inc. (Citizen Group); Ohio Partners for Affordable Energy (OPAE); Cargill, Inc.; Reliant Resources, Inc. (Reliant); Industrial Energy Users-Ohio (IEU-Ohio); Constellation Power Source, Inc. (CPS); Ohio Manufacturers' Association (OMA); Northwest Ohio Aggregation Coalition on behalf of City of Toledo, Lucas County, City of Maumee, City of Northwood, City of Northwood, City of Oregon, City of Perrysburg, City of Sylvania, and Village of Holland (NOAC); The Northeast Ohio Public Energy Council (NOPEC); Ohio Energy Group; The Kroger Company; Local 270 Utility Workers; PSEG Energy Resources and Trade (PSEG); Midwest Independent Power Suppliers; National Energy Marketers Association; Calpine Corp.; Ohio Hospital Association; and Vallourec & Mannesmann Tubes Corp.

At the hearing on February 11, 2004, Saint Charles Mercy Hospital's request for intervention was denied for being filed beyond the time prescribed. NOPEC's motion for a Commission review of FirstEnergy's transition charges was also denied at that time and several parties noted their continuing objection to the procedural schedule.

By Entry dated October 23, 2003, a procedural schedule was set for the case that included a technical and procedural conference on November 5, 2003; Applicants' testimony to be due on November 12, 2003; intervention and objection filings due by November 19, 2003; testimony from all parties other than Applicant due by November 19, 2003; the evidentiary hearing set for December 3, 2003; and local public hearings set for November 20, 2003 at Toledo, November 24, 2003 at Cleveland and November 25, 2003 at Kent. By attorney examiner Entry dated November 7, 2003, the schedule was adjusted in response to requests for extensions filed by the OCC, Ohio Marketers Group, GM and WPS. The new schedule set the date for the filing of Applicants' testimony to be November 19, 2003; intervention and objections to be filed by December 3, 2003; and the evidentiary hearing to be held on December 17, 2003. On November 25, 2003, the Commission further extended the procedural schedule to require Staff's testimony to be filed by January 7, 2004; interveners' testimony to be filed by January 21, 2004; and the hearing to begin on February 11, 2004. By attorney examiner Entry dated January 23, 2004, the filing of interveners' testimony was extended until February 6, 2004, with the hearing date remaining as February 11, 2004. By attorney examiner Entry dated February 2, 2004, the interlocutory appeal of several parties to the January 23, 2004 Entry was not certified. The parties filing the appeal had argued that the procedural schedule did not provide sufficient time for case preparation.

On December 9, 2003, all intervening parties that intended to supply generation services to retail customers were requested to file the quantity of power that they would be willing to supply during the period January 1, 2006, through December 31, 2008, on a load-following basis, with their testimony.

On November 19, 2004, FirstEnergy filed the direct testimony of its witnesses. The Staff filed its testimony on January 7, 2004. Objections and testimony were filed by intervening parties on February 6, 2004.

The local public hearings were held as scheduled in Toledo, Cleveland, and Kent. The testimony in Toledo was mainly directed to the issue of the parties and the Commission needing more time to effectively consider the application in the case. The speakers, public officials and other local ratepayers also expressed their opposition to the application allowing for the continued collection of stranded costs. In Cleveland, the need for more time was raised and there were several speakers commenting on the unfairness of the current collection of stranded costs that resulted from the ETP case. In Kent, a small number stated their general opposition to high rates.

The hearing on the case commenced on February 11, 2004, and continued through February 24, 2004. On February 25, 2004, FirstEnergy offered rebuttal testimony and a revised rate stabilization plan. On March 1, NOAC/NOPEC, WPS, OCC and Ohio Marketers Group/OMA presented surrebuttal testimony. A partial Stipulation and Recommendation ("Stipulation"), which purports to resolve some issues in this case for certain signatory parties was filed on February 11, 2004. The Stipulation was signed by FirstEnergy, the Ohio Energy Group, the Ohio Hospital

Association, Ohio Partners for Affordable Energy, Cargill, Inc. and the Industrial Energy Users-Ohio.

Post hearing briefs were filed on March 17, 2004, and reply briefs were timely filed on March 31, 2004. Letters from consumers and other interested groups, expressing opposition to FirstEnergy's application, have been filed in the docket of this case. On April 21, 2004, at the request of the OCC, marketer, supplier and governmental aggregator intervening parties, oral argument by interested parties and the Applicants was presented before the full Commission.

II. FIRSTENERGY'S REVISED APPLICATION

FirstEnergy proposes in its application to either (1) establish a competitive bidding process (CBP) to determine standard offer generation service rates commencing as of January 1, 2006 under which the prices for generation services would be determined by the current market prices, or (2) implement a comprehensive RSP designed to provide stable long-term competitive pricing of energy services for customers, assure supplies of electricity and enhance economic development within its service areas. The CBP has been referred to as option 1 while the RSP as been referred to as option 2.

Option 1, the CBP, would establish generation prices based upon a competitive bid to be undertaken during 2005 and would include provider of last resort (POLR) responsibility. The details of the CBP would need to be worked out in accordance with the Commission's Market-Based Standard Service Offer (MBSSO) and CBP rules adopted by the Commission on December 17, 2003. Offers to provide competitive retail electric service (CRES) would be solicited in a FirstEnergy-wide competitive bidding auction process that simultaneously seeks offers for such service in each of the three FirstEnergy utility service areas in Ohio. The result would be a wholesale sale from the winning bidders to the utilities, and a retail sale from the utilities to customers. The CBP option provides that the Commission would approve the auction process, monitor the conduct of the auction, and certify the auction results. In the event of a winning bidder's failure to meet it commitments, the price paid by customers would be adjusted to reflect the market price at the time of the default or to cover the bidder's failure to supply. According to the application, under this proposal, price and supply risk is shifted to customers, although there would be recourse against suppliers that fail to meet their contractual obligations. (FirstEnergy Application, Exhibit 1 at 1-4).

Option 2, the RSP, is intended to secure for FirstEnergy customers the benefits of adequate generation supply at stable prices for an extended period. As outlined in the application and as revised by the rebuttal testimony of FirstEnergy witness Alexander, the major components of the RSP include:

1. Current generation rates (sometimes referred to as "little *g*") will continue through December 31, 2008, subject to certain exceptions for costs that FirstEnergy contends are generally beyond its ability to control, e.g., taxes, fuel and

certain regulatory costs, but in some instances subject to a cap, and other changes that are currently allowed by Ohio Revised Code or applicable tariffs (Section I, Paragraph 5; Section II, Paragraph 1).

2. Distribution rates would continue to be frozen through December 31, 2007, except for additional revenues necessary to recover the costs of complying with changes in laws, rates or regulations related to environmental (distribution-related), taxes, or in the event of an emergency under Section 4909.16 of the Revised Code, or for increased costs incurred to improve reliability of service, provided that any such reliability-related increases shall be deferred for recovery through the extended Rate Stabilization Charge as set forth in Section II Paragraph 8. Residential customer charge credits currently in effect for FirstEnergy will be extended as a reduction in other charges. Transmission rates would be adjusted as established by the Federal Energy Regulatory Commission (FERC) or applicable Regional Transmission Organization (RTO) (Section I, Paragraphs 6 and 7).

3. Effective January 1, 2006, a Rate Stabilization Charge (RSC) will be established. The RSC will end for all of the FirstEnergy companies, unless the RSP is terminated early, with usage through December 31, 2008. The RSC charge will be at the same level as the generation transition charge (GTC) (Section II, Paragraph 2(a)).

4. The RSC will be a non-bypassable charge, except that aggregators and industrial/commercial customers will be given an opportunity to enter into contracts for the period January 1, 2006 through December 31, 2008 under which, if the Applicants are no longer obligated to reserve capacity to meet the requirements of such customers under the contracts, then the shopping credits for such customers will be equal to the generation charge (which otherwise would be set at the current little "g" charge) plus a percent of the RSC. If government aggregators or commercial/industrial customers enter into a firm generation service electric contract(s), i.e., satisfying the full capacity, energy and transmission requirements associated with such customer loads and with a credit worthy supplier, for a binding term (i) commencing January 1, 2006 through December 31, 2008, and sufficient evidence of such contract(s) is provided to the FirstEnergy prior to December 31, 2004, or (ii) commencing January 1, 2007 through December 31,

2008 and such notice is provided prior to December 31, 2005, or (iii) commencing January 1, 2008 through December 31, 2008 and such notice is provided prior to December 31, 2006, then such government aggregators and/or commercial/industrial customers shall be entitled to increase the credit by selecting at the time of the applicable contract notice set forth above either the credit set forth in Paragraph 2(b)(1) or 2(b)(2) of Section II for the entire period of the contract and for aggregators all customers within the aggregated group shall be under the same credit election. In no event shall the total shopping credit as determined in this Section for any customer be greater than the shopping credit set forth in Attachment 5 of the RSP, plus any riders or charges implemented pursuant to Section I, Paragraph 5. The shopping credit for customers that do not enter into such contracts will be set at the generation charge during the period of the RSP. Returning customers would only be exposed to then-current market prices for a limited period of time, and any excess charges will be spread over 12 months, without interest, at the customer's request (Section II, Paragraph 2(b)).

5. If, following the market development period, the Applicants do not maintain at least 20% shopping within the classes that are subject to the shopping credit limitation set forth in Section II, Paragraph 2(b), as currently determined, then the Applicants will continue to make available for that class market support generation under generally the same terms as currently in effect up to the amount needed to attain 20% shopping at a price equal to 85% of the generation charge otherwise applicable to the customer, but not lower than 1.5 cents per kWh (Section IV, Paragraph 4).

6. The Companies will waive the right to seek a reduction in the shopping credits, and to extend the recovery of the RTC for economic conditions and other factors that have affected or will affect kWh sales, as set forth in Case No. 99-1212-EL-ETP, except that the shopping credits in effect for calendar year 2004 will continue during 2005. The Companies will begin to accrue and defer interest on the shopping credit deferred balances and other deferrals created under the Plan (Section II, Paragraph 9; Section VIII, Paragraph 6).

7. The GTC charge will be reduced effective January 1, 2004 through December 31, 2005 to incorporate a reduction

within that charge to reflect the 5% residential generation credit and the residential customer charge credits. Effective January 1, 2006, those credits will be reflected as reductions in the RTC charge. This will allow those credits to continue through the recovery of regulatory transition costs, and, as discussed below, be further extended. As a result of lowering the transition cost charges, the time period for recovery and amortization of certain regulatory transition costs will be fixed at the earlier of specific dates or attaining certain kWh sales levels for each Applicant. When those dates or sales are reached, the RTC will be extended to recover the shopping credit incentive deferrals and other deferrals created by the Plan, on a dollar-for-dollar basis, but no later than through December 31, 2010. The extended RTC charge will be set at the same level as the RTC charge. Termination of the Plan will not impact the RTC or extended RTC recovery periods or rates (Section II, Paragraphs 6, 7 and 8; Section I, Paragraphs 2 and 12).

8. Energy efficiency and economic development funds will be made available during the period the Plan is in effect (Section III).

9. A competitive bidding process will be established to test the generation price provided for under the Plan against market prices. If the market prices are lower, the Commission may terminate the RSP and accept the bids for generation service within the service areas of the Applicants. The Commission may also elect to terminate the Plan at any time and for any reason with certain notice (Section IV and V).

10. The Applicants may only terminate the Plan if, as a result of environmental requirements, generating units currently owned by the Applicants are shut down or retired in an aggregate amount that exceeds 250 MWs (Section VI).

11. The requirement that the Applicants corporately separate will be extended until 12 months after the Commission terminates the RSP or until December 31, 2008, whichever occurs earlier (Section VII, Paragraph 2).

12. The termination dates for special contracts as such dates would have been determined under Case No. 99-1212-EL-ETP will not be affected by the RSP, but in no event shall such contracts terminate later than December 31, 2008, provided that, upon request of the customer, or its agent,

> received within 30 days of the Commission's order in this case, FirstEnergy may extend the term of any such special contract through the period that the extended RTC charge is in effect for such FirstEnergy utility, if doing so would enhance or maintain jobs and economic conditions within its service area (Section VIII Paragraph 8).

Initially, the Commission must decide whether either FirstEnergy's proposed CBP option or its RSP option provides a reasonable mechanism for providing electric service to retail customers after the MDP ends December 31, 2005. FirstEnergy, Staff, IEU-Ohio, and certain other individual parties and customer groups support the approval of a RSP, while OCC, CRES providers, OMA, and certain other parties support the implementation of a CBP and MBSSO established pursuant to Section 4928.14, Revised Code. As discussed more fully below, the Commission finds that a properly formulated RSP can provide rate certainty, continue to maintain a competitive market, and provide financial stability for FirstEnergy. We also find that inasmuch as many parties to this proceeding, including OCC, marketers, and other aggregators, support the use of a CBP, a CBP should be conducted by First Energy to evaluate whether customers are better served by the establishment of an RSP or a CBP. If the CBP provides prices for generation service below that of the RSP, then there may not be a need for the RSP.

Those in support of the RSP argue that the RSP was offered in response to the Commission's September 23, 2003 entry in Case No. 03-1461-EL-UNC regarding the establishment of FirstEnergy's shopping credits for 2003. In that entry, the Commission requested that FirstEnergy develop a plan that balanced three objectives: (1) rate certainty, (2) financial stability for FirstEnergy, and (3) the further development of competitive markets. These parties believe that the RSP will meet all three objectives, Staff agreeing if certain RSP modifications, discussed later in this order, are adopted by the Commission. FirstEnergy witness Alexander testified that the RSP represents FirstEnergy's determination of the parameters within which it is willing to assume the risk of continuing to supply POLR services to its Ohio customers at a fixed, market-based generation price, using its generation assets after the end of the MDP, while still maintaining its financial integrity (FirstEnergy Ex. 1 at 9). These parties argue that the RSP provides for stable rates through 2008, subject to limited Commission-approved adjustments, while continuing shopping credits at levels that are already supporting shopping. Its is also argued that the RSP, as revised, provides FirstEnergy with the ability to maintain financial stability through the term of the Plan by adjusting kWh sales targets and extending the period for regulatory transition cost recovery to account for the lower-than-expected sales resulting from the sluggish economic conditions and the effect of the accrual of carrying charges (FirstEnergy Ex. 3 at 2-3; Staff Ex. 4 at 3-4).

In addition to meeting the Commission's stated goals, these parties believe that uncertainties and enhanced risks exist with the implementation of a CBP. They assert that there have been delays in the establishment of RTOs and that competitive generation markets have not developed as contemplated by the Ohio General Assembly. Staff witness Cahaan pointed out that a well-functioning and competitive wholesale market is a necessary precondition for an efficient retail market and that such a market does not exist at present (Staff Ex. 3 at 3). The parties in support also state that the RSP provides customers the opportunity to shop against the generation fixed plan and, if the market supports lower pricing, customers can shop. The RSP also provides the Commission the ability to periodically test the RSP prices against a competitive bidding process. If the market prices are lower, the Commission may terminate the RSP and accept the bids for generation service (FirstEnergy Ex. 6 at Section IV). FirstEnergy also points out that, as the electric industry increases its use of natural gas to fuel new generation facility, the cost to generate electricity increases and becomes more unstable with increases in the price of natural gas.

IEU-Ohio and others believe that the Commission must take note of the current state of the electricity market. They point out the Midwest joint and common market, to be formed through the virtual combination of the Midwest ISO (MISO) and PJM Interconnect LLC (PJM), has not developed as planned and is not forecasted to begin full operation until late 2004 or early 2005. It is further noted that the expected integration of American Electric Power (AEP) and other electric distribution utilities (EDU) into PJM has been continually delayed due to a variety of reasons and that efforts by FERC to standardize the design of electric markets, to address reliability and pricing concerns, has met stiff opposition. They believe that these matters have hindered electric restructuring and that a RSP is an appropriate mechanism under which electric service should be provided until these federal matters can be resolved.

Those parties that oppose the application urge the Commission to reject the RSP. They argue that the RSP does not meet any of the three goals set forth by the Commission for establishing a RSP. They assert that the RSP does not stabilize rates, does not promote competitive markets, and goes well beyond what could be considered reasonable measures to provide financial stability for FirstEnergy. It is argued that the RSP provides a windfall for FirstEnergy by ensuring recovery of all its costs, while providing for the continued collection of generation transition costs well beyond the end of the MDP in the form of a RSC. They point to possible increases in both the generation and distribution rates during the term of the RSP as evidence that rates charged customers will not be stable. They point to FirstEnergy's ability to increase generation costs up to 15% per year for the three years of the RSP period and the deferral of distribution costs associated with improvements in service reliability during 2006 and 2007. They also point out that shopping credits as proposed by FirstEnergy will provide no incentives for most customer classes to shop. These parties also contend that the RSP requires unwarranted concessions from the existing ETP, such as being able to charge interest on the regulatory transition cost deferrals, keeping the 2004 shopping credit in effect for 2005, and extending the regulatory transition cost recovery periods and adjusting kWh sales targets. (Dominion Ex. 1 at 4; Cleveland/WPS Ex. 1 at 10 and Ex. 2; OMG Ex. 2 at 11; NOAC/NOPEC Joint Ex. 2 at 13-14; GM Ex. 1 at 4-14; and OCC Ex. 1 at 3-10).

OCC, OMA, OMG and other parties would prefer that a CBP be adopted as set forth by Section 4928.14(B), Revised Code. They recognize, as does the Staff, that option 1 put forth by FirstEnergy is lacking in many specifics and that a more fully developed

CBP would have to be submitted and approved by the Commission before a CBP could be implemented. However, they support such a process. OMG believes that the wholesale market is mature enough to support market-based pricing and that sufficient generation and transmission capacity exist for there to be reliable alternatives to FirstEnergy's generation. OMG witness Roach expects that enough power plants and transmission capacity will be available to assure robust competition to serve FirstEnergy's customers. Dr. Roach testified that there is 22,000 MW of generation available to compete for FirstEnergy's 13,500 peak summer load and that 9,300 MW of non-FirstEnergy generation would be available to replace FirstEnergy's generation. He also testified that the East Central Area Reliability Council (ECAR) region has a reserve capacity of 36.9%. Additionally, he noted that currently, on a MW basis, 38% of CEI's load is supplied by CRES providers, 29% of OE's load, and 24% of TE's load (RRI/CPS Ex. 1 at 15-22). OMG argues that a CBP would not entail a significant risk to ratepayers and that there is a regional market that can support the ability to deliver power into the FirstEnergy service territory. NOAC's witness Frye and WPS witness Giesler have similarly testified that reserve margins in the ECAR region are increasing expected to exceed target levels in the next several years (NOAC/NOPEC Ex. 1, Attachment MRF-1; WPS Ex. 2 at 21). They argue that there is no reason to believe that new supplier's generation will be any less dependable than FirstEnergy's generation and question the reliability of the RSP where FirstEnergy can cancel its obligations under the RSP if 250 MW of its generation is lost.

It is also argued by OMG that a review of the testimony, regarding CRES providers' ability to provide power, supports the use of a CBP. Reliant filed an affidavit that it had 1,300 MW in the service area that was available and more could be brought in if the price was right. Further CPS indicated that it could potentially bring in 2000 MW of electricity at a price below FirstEnergy total generation price of 4.6 per kWh calculated by witness Alexander (RRI/CSP Ex. 1, 2 and 3). NOAC also argues that there is no need for a RSP in FirstEnergy's territory inasmuch as FirstEnergy's situation is entirely different from the circumstances of Dayton Power and Light Company (DP&L), Case No 02-2779-EL-ATA, where the Commission approved a rate stabilization plan (DP&L Order). NOAC contends there was no shopping to speak of in DP&L's service area, that DP&L's MDP was to end in the beginning of 2004, and that DP&L's residential customers pay only 65% of what TE residential customers pay.

Several of the parties opposing the RSP argue that the generation rates established through the RSP are not market based and, therefore, do not meet the requirements of Section 4928.14, Revised Code. They argue that FirstEnergy has put forth a mechanism to establish a price at which it will provide generation service after the MDP, and has asked the Commission to approve such a mechanism as its filing for MMSSO under Section 4928.14 (A), Revised Code. NOAC, OCC, and others point out that neither component of the generation price ("g" plus the RSC) has any connection with the market. They argue that "g" was defined in the FirstEnergy ETP case as the amount that is left over after subtracting transmission, distribution, and other unbundled components from the bundled price and making tax-related adjustments. Consequently, they assert that this residual amount has no connection to the price of generation in the unregulated market and does not meet the criteria set forth in Section 4928.14, Revised Code.

The Commission, after considering the numerous arguments for and against the adoption of a RSP, finds that it is prudent to establish a RSP for FirstEnergy unless the CBP can provide better benefits for customers. We concur with our Staff that a well-functioning and competitive wholesale market is a necessary precondition for an efficient retail market and that such a market does not exist at present. Efforts by FERC to standardize the design of electric markets to address reliability and pricing concerns have met stiff opposition and may take considerably more time to put in place. Further, the delays that have occurred in the establishment of RTOs and the development of competitive wholesale generation markets require that we develop a standard service offer that provides protections against the possibility of rate shock once the MDP ends, as well as one that promotes further development of a competitive generation market. The Commission believes that the development of a plan that balances rate certainty, further development of competitive markets, and financial stability for FirstEnergy could provide the needed regulatory treatment until a fully functioning competitive wholesale market is in place.

With respect to the arguments put forth by OMG and others that there is a sufficiently developed competitive market based on available capacity in the ECAR region and the amount of shopping that is currently occurring in FirstEnergy service territories, these conditions may not necessarily lead to a fully functioning market at the end of 2005. The 2001 through 2005 shopping credits approved in FirstEnergy's ETP case, which have helped promote shopping, would not be in effect after 2005 and current factors that support a high level of available capacity may change in the future. As some parties acknowledge, it cannot be predicted what wholesale generation prices will be during the 2006 to 2008 time period (Tr. VII at 52; Tr. VIII at 53). Our Staff and FirstEnergy argue that the risk of substantial wholesale power increases supports the implementation of a RSP. OMG witness Scharfman testified that, on average, OMG CRES providers' fixed generation prices during the RSP would be 29% higher than the "g" shopping credit proposed by FirstEnergy (OMG Ex. 2 at 10-11). NOAC/NOPEC witness Frye and OMG witness Roach, on the other hand, see no indication that power pricing during the period 2004 through 2008 is likely to rise substantially and that power supplies would be available at prices likely to be better than the cost-plus rates proposed in the RSP (NOAC/NOPEC Ex. 1 at 5-6; Reliant-CPS Ex. 1 at 6). Inasmuch as no one can foretell the future and there still remains needed action to be taken on the federal level, we find it prudent to establish a RSP for FirstEnergy if a CBP does not provide better benefits.

We also believe that the establishment of a RSP is supported by the legislature. On October 15, 2003, the Ohio House of Representatives Select Committee to Study Ohio's Energy Policy issued a report to the House of Representatives (Energy Report). This Energy Report was created by the House Energy Policy Committee, which was formed to evaluate the state of Ohio's current energy resources and to recommend public policy changes to ensure that Ohio will have sufficient supplies of safe and reliable energy now and in the future. The Energy Report states:

> The legislature gave the PUCO a tremendous amount of supervision and management authority in SB 3, and it continues to monitor the market as we move through the transition periods. For example, to give competition more time to develop, the PUCO approved an extension of the transition period for Dayton Power & Light. Consumer advocates, regulatory officials and industry representatives worked together to craft a new plan, agreed to by the parties, to continue the framework of a competitive market while allowing some protection to customers. **The members encourage the PUCO to continue to take the necessary steps, whether by rule or a request for legislation, to ensure that a healthy competitive market is in place before full competition begins.**
>
> Energy Report at 3 (emphasis in original).

If we implement a RSP, we are taking the necessary steps to ensure that a healthy competitive market is in place before full competition begins. Further, we find that our actions are consistent with the state of Ohio's policy to recognize the continuing emergence of competitive electricity markets through the development and implementation of flexible regulatory treatment as set forth in Section 4928.02(F), Revised Code.

We are also of the opinion that a properly structured RSP can provide stable rates through 2008, fulfill requirements of Section 4928.14, Revised Code, and continue to foster the development of a competitive market. One important aspect of FirstEnergy's RSP is that it provides customers the opportunity to shop against the stabilized generation rate plan and, if the market supports lower pricing, customers can shop. Those parties that oppose the RSP have raised numerous arguments why the RSP should be rejected, or if not rejected then modified to comply with Section 4928.14, Revised Code, and to ensure that such a plan does not provide windfall profits to FirstEnergy or harm the continued development of a competitive market. The issues raised by these parties will be considered in more detail as part of the Commission's review of the specifics of FirstEnergy's RSP.

FirstEnergy's proposed RSP provides that, no more often than annually, the Commission shall undertake or cause FirstEnergy to undertake a competitive bid for generation service for the totality of the load within the respective service areas of the operating companies. It further provides that such bid process would be sufficient to meet the supply requirements for all customer classes of all of the operating companies, including customers served under special contracts and by alternative suppliers, except for contracts that meet the requirements set forth in Section II Paragraph 2(b); would be for a calendar year of service; and would be measured against the generation charge set forth in Section II Paragraph 1. The bidding process would cover a period commencing at least 12 months after the Commission's determination as to whether or not to accept the results of such bidding process. The Commission could elect not to cause a competitive bid to be undertaken for good cause shown given the then existing market conditions.

The RSP further provides that the CBP would be established within six months of the approval of this RSP through the cooperative efforts of FirstEnergy, the Staff, the OCC, and other interested parties as directed by the Commission. The process would be similar to that used in New Jersey. Unless the Commission rejects the results of the test CBP, the Commission would hold a hearing to determine whether it is in the best interest of all of FirstEnergy's customers to accept the results of such CBP, giving consideration to the fact that such acceptance would cause the termination of the RSP.

OCC argues that FirstEnergy CBP requires more detail before the Commission should approve it. It also asserts that it would be difficult for the Commission to hold a New Jersey style auction every year just to determine whether the market can support a CBP. OCC believes that suppliers will not participate unless the auction is a binding commitment. Therefore, it would be difficult for the Commission or FirstEnergy to hold a CBP to determine whether the RSP should be terminated. Additionally, FirstEnergy's proposal requires the Commission to give 12 months notice of termination. OCC argues that requiring bidders to commit supply a year in advance of delivery could be problematic.

GM, WPS and Cleveland argue that the criteria used in the CBP are fatally flawed. In addition to the various procedural constraints addressed by OCC, these parties and NOPEC argue that, by requiring the Commission to compare marketplace prices to FirstEnergy's artificial "g" value, the CBP merely proposes an illusory choice to the Commission. GM witness Chernick testified that the CBP will measure bids against generation prices much lower than those that FirstEnergy would be charging. While FirstEnergy would be charging "g" + RSC, suppliers would bid against "g" alone. He stated that:

> Based on the *g* and GTC values underlying Mr. Alexander's estimate of *g* and RSC, provided in GMEC-10-1, the system-wide average *g* would be 2.94¢/kWh, and RSC would be 1.73¢/kWh at December 31, 2005. If the Commission wanted to hold an auction for competitive supply for 2007, that auction would be held an auction (sic) late in 2005, to allow FirstEnergy one year's notice before the competitive suppliers took over on January 1, 2007. In order to win the auction, the bidders would have to offer POLR services for 2007 for less than 2.94¢/kWh.

See GM Exhibit 1 at 41- 42

WPS and Cleveland recommend that any competitive bid to evaluate the RSP should compare market prices against a price-to-compare that contains a generation price that reflects FirstEnergy's fully embedded cost of generation, the RSC, and other costs they argue should be avoidable to shopping customers.

GM also asserts that the CBP is flawed in that it requires a bidder to bid for the totality of FirstEnergy's load, with limited exception. GM claims that FES may be the only CRES provider with the level of resources to make such a bid (GM Ex. 1 at 44-45). GM argues that the CBP is unworkable as proposed by FirstEnergy. OMA and OMG also believe that the CBP is unworkable. OMA notes that, in all probability, it would take a year and a half to switch to CBP prices. OMG supports the arguments raised by other parties and notes that having the Commission hold a hearing to approve the winning bid would deter bidders.

FirstEnergy states that the Commission can hold a competitive bid under the RSP and terminate the RSP, thus using the competitive bid results as the market-based standard service offer as permitted by Section 4928.14(B), Revised Code. Applicants argue that if the RSP remains in effect, it is because the Commission finds the RSP is a reasonable substitute for the CBP.

The Commission supports the use of a CBP to continue to monitor the necessity of a RSP on a going forward basis. We believe that a CBP should be conducted to assure the Commission and all interested stakeholders that the charges for generation service under the RSP do not exceed long-term market prices that result from a CBP. However, the CBP proposed by FirstEnergy requires modifications if it is to serve any meaningful purpose. We agree with the various parties in opposition to FirstEnergy's CBP and find that the Applicants' proposal to measure the results of such a CBP against the generation charge provides no meaningful comparison to determine whether or not to end the RSP. Once a CBP has been conducted, such result can be provided to our Staff for its analysis of the appropriate comparison and the Commission can then determine whether to approve the winning bids or maintain the RSP. It is not likely that the Commission would hold a hearing before making such a determination. We believe that providing for a hearing, as FirstEnergy proposes, would unduly delay the process and be an impediment to receiving the lowest bids possible. The Commission envisions a period of days, not months, to analyze the bids that are received. Further, we would envision that the CBP would encompass the Applicants' total load to cover the risk of providing POLR coverage for all customers, including customers under contracts that meet the requirements set forth in Section II Paragraph 2(b) of the RSP. However, such a CBP, patterned after a New Jersey model, would not require a single bidder to bid for the entire load. The bids should cover POLR service for the entire 2006-2008 period so as to be on a comparable basis with the three-year RSP. The Commission will hire a consultant to assist in its analysis of the bids. The cost of such consultant shall be paid by the Applicants and recovered through the extended RTC mechanism.

The Applicants have proposed that the service provided under a CBP would be for a calendar year of service and would cover a period commencing at least 12 months after the Commission's determination as to whether or not to accept the results of such bidding process. In keeping with these provisions, the Commission will cause the Applicants to undertake a CBP consistent with our findings above, and such CBP will use an independent third-party auctioneer to provide confidence in the impartiality of the auction process. The Applicants shall schedule a meeting with our Staff and interested parties to this proceeding to establish further requirements of the CBP. Binding bids from the auction will be provided to the Commission's Staff no later than December 1, 2004, so that if the Commission decides to accept the bids they could be effective beginning January 1, 2006.

III. FIRSTENERGY'S REVISED RATE STABILIZATION PLAN

A. Generation Charges

As part of the RSP, FirstEnergy proposes rates for generation service beginning in 2006 through December 31, 2008. The generation charge equals "g" in effect as of December 31, 2005, without regard to the transition rate credit rider, plus any riders or charges implemented pursuant to Section I, Paragraph 5 of the RSP (FirstEnergy Ex. 6 at Section II, Paragraph 1).

Section I, Paragraph 5 provides that FirstEnergy may adjust, using the year 2002 as a reference year, the tariffed generation charge beginning January 1, 2006 for actual costs incurred resulting from any of the following events set forth in Paragraph 5(d):

1. an increase in the cost of fuel, including the cost of emission allowances consumed, lime, stabilizers and other additives, and fuel disposal; nuclear security; and environmental costs, including the costs of capital during new construction. Nuclear security, fuel disposal and/or environmental cost increases may be recovered only if they are mandated by law, rule, regulation, or administrative or court order.

2. an increase in regulatory costs actually incurred on or after January 1, 2006 and mandated by law, rule, regulation or administrative or court order and not otherwise specifically addressed herein.

3. an increase in taxes.

For purposes of determining any additional revenues that could be recovered due to the changes noted above, all reductions in such costs will be used to reduce the additional revenue requirement. Such adjustments would also have to be approved by the Commission. Increases resulting from paragraphs 1 and 2 above could occur no more often than once every 12 months, and the aggregate of the adjustments set forth in paragraph 1 for any 12-month period may be no greater than 15% of the tariffed generation charge in effect at the beginning of the 12-month period, provided that the annual percentage shall be increased to the extent that the immediate prior year's 15% limit was not utilized. The amount in excess of the above limits, would be deferred by FirstEnergy for recovery through the extended regulatory transition charge (RTC) as set forth in Section II, Paragraph 8 of the RSP.

FirstEnergy argues that the proposed generation rates provide a degree of certainty and stability in that wild fluctuations due to unpredictable markets will not occur. However, given the state of the electric industry on both the wholesale and retail levels and the uncertainty surrounding issues dealing with MISO, environmental requirements, and unanticipated changes in laws, FirstEnergy contends that it must have the ability to seek rate increases for additional costs over which it has no reasonable control. FirstEnergy also argues that the fact that the RSP provides for some increase in rates is consistent with what would happen in a mature market over time and that unrecovered cost increases at some point would jeopardize FirstEnergy's ability to provide service. FirstEnergy emphasizes that the allowed cost increases would be only those beyond the control of the FirstEnergy operating companies.

Staff supports FirstEnergy's generation rate proposal with one exception. Staff recognizes that it is reasonable and efficient to permit for some escalation of generation charges for reasons specified by FirstEnergy. However, Staff witness Cahaan testified that Staff does not support the deferral of generation costs above the 15% level, believing that allowing such deferrals would shift excessive risk to customers. Staff is also concerned about the shifting of generation costs to the EDU for future recovery from all distribution ratepayers, including those who opt out of taking generation from FirstEnergy (Staff Ex. 3 at 10-11).

OCC takes issue with numerous aspects of the proposed generation rate. OCC argues that the annual adjustments of up to a 15% cap (approximately 50% over three years compounded) are excessive and unsupported by the record. It points to the DP&L post-MDP RSP stipulation approved by the Commission which provided for a total potential increase in similar costs of 11% over a three-year period. OCC also argues that the Commission should ensure that the RSP contains detailed language eliminating ambiguity regarding the exact type of costs that can be recovered under the cap.

If the Commission is to consider increases to generation costs, OCC contends that the Commission should recognize that only a small portion of a plant's life is likely to occur during the 2006 through 2008 period of the RSP (OCC Ex. 1 at 20). Therefore, the Commission should not permit the entirety of environmental capital costs, or even the related carrying charges during construction, to be charged to customers during 2006 through 2008, if the benefits of those costs would occur for the plant owners over the life of the plant, including time after the RSP has ended. Likewise, in determining which environmental costs should be included in the generation cost increases and the deferrals, the Commission should recognize that anticipated environmental costs at the time of FirstEnergy's ETP filing may have been considered in the market valuation of the plants used in determining the amount of GTC that FirstEnergy could charge. OCC believes that, if cost adjustments are to be considered, then only costs that are truly new and not incorporated into prior plant valuations should be included. OCC witness Pultz testified that FirstEnergy's proposal seems to allow FirstEnergy to charge Ohio customers environmental costs, including the cost of capital during construction, for certain environmental projects even though those projects related to plants that do not serve Ohio customers (OCC Ex. 1 at 21). OCC argues that the Commission should modify the RSP to ensure that environmental costs of plants that FirstEnergy acquires, or that belong to companies that merge with FirstEnergy, do not qualify for treatment unless those plants actually serve Ohio customers, and unless this service to Ohio customers does not displace service by plants that FirstEnergy has disposed of after including their environmental costs. Additionally, OCC asserts that the 2002 costs are inappropriate baseline costs for the cost of fuel, as well as the other costs eligible for increase in the RSP, when calculating the tariffed generation rate increases. Instead, OCC recommends that the Commission use the level of costs determined in the ETP proceeding, which is what the current generation component in rates is based upon. Mr. Pultz testified that the 2002 cost of fuel serving as the base line for increases in generation, 1.08 cents/kWh (FirstEnergy Ex. 1, Ex. 2 at Attachment 2), is below the average rate of the approximated 1.3 cents/kWh built into current rates (OCC Ex. 1 at 21 and Attachment H). OCC argues that only increases over the costs of fuel built into current rates should be allowed to increase the generation charge. OCC's overall position is that the Commission should not authorize FirstEnergy to increase the tariffed generation charge or allow any deferrals of additional charges by an uncertain and unconstrained amount.

NOAC and other parties argue that no increase for generation costs should be allowed during the RSP. NOAC believes there is too much room for FirstEnergy to manipulate which customers pay what fuel costs. NOAC/NOPEC witness Frye testified that the cost of such increases for generation for 2006-2008 could possibly be as high as $1.3 billion (NOAC/NOPEC Ex. 1 at 52). OMG also disagrees with the provision that would allow FirstEnergy the option to either collect or defer increases in generation costs. OMG argues that deferring such costs is anti-competitive. When the increases are added to generation rates, there is an offsetting increase in the shopping credit. If cost increases are deferred, shopping customers will ultimately help pay those costs through the RTC, in effect creating a cross subsidy.

Considering the approved ETP for FirstEnergy and the provision for an appropriate rate stabilization charge as part of a RSP, adjustments to generation charges during the RSP should be limited to cost increases related to material changes in tax regulations or laws. As discussed in this opinion and order, the Commission is establishing a RSC which will appropriately compensate the Applicants for providing stable rates for electric service for the period 2006 through 2008. To provide for generation cost increases based on all the provisions proposed by the Applicants would be overly complex and make rate stabilization for generation service illusory. Not only would FirstEnergy's proposed RSP permit it to increase the generation charge almost 50% over three years due to increases of fuel and other related costs, when compounded, it would also permit increases in generation charges due to regulatory costs incurred on or after January 1, 2006. Such provisions create too much uncertainty to properly evaluate the benefits and risks of the Plan for FirstEnergy and its costumers. We also would envision lengthy arguments over what constitutes proper costs that could be recovered by such adjustments. We believe that limiting any generation charge adjustments to strictly material changes in taxes limits the degree of complexity and provides rate stability while insulating the Applicants from material changes in taxes. Further, we recognize that rate stability not only benefits electricity consumers but FirstEnergy by providing a customer base for its generation. Accordingly, we believe it is appropriate to limit any adjustments to the generation rate to material changes in taxes as discussed above.

B. Distribution Charges

With respect to distribution rates, the RSP provides that distribution electric rates and charges as unbundled in the ETP will continue to be frozen through December 31, 2007, except as otherwise provided in Section I and except for additional revenues necessary to recover the costs of complying with changes in laws, rules or regulations related to environmental (distribution-related), taxes, or in the event of an emergency under Section 4909.16 of the Revised Code, or for increased costs incurred to improve reliability of service, provided that any such reliability-related increases shall be deferred for recovery through the extended RTC as set forth in Section II paragraph 8. For purposes of determining any additional revenues that could be recovered due to the changes noted above, all reductions in such costs will be used to reduce the additional revenue requirement.

FirstEnergy states that it would file an application for Commission review and approval if it sought to increase distribution rates or create additional deferrals, noting that it has the burden of showing that the costs were reasonable (Tr. I at 230-233; Attachment 1 of FirstEnergy's brief). FirstEnergy witness Alexander testified that the company could implement such increases after January 1, 2004 (Tr. I at 231). FirstEnergy's reasons for having the ability to adjust distribution rates are similar to those for generation increases. FirstEnergy asserts that the operating companies have little control over changes in law or regulations, and necessary costs related to improving distribution reliability. Additionally, FirstEnergy contends that its frozen distribution rates should remain so during the RSP period, with limited exceptions, to maintain stable rates and that the filing of a Chapter 4909, Revised Code, application to increase rates for distribution service once the MDP expires would not be consistent with the goal of rate stabilization. FirstEnergy asserts that its plan provides for rate stability while maintaining reliable service through the ability to recover costs of maintaining the system.

Staff has concerns with continuing the distribution rate freeze beyond 2005 and for the deferrals associated with costs incurred or necessary to improve reliability of the distribution service. The Staff believes that the measurement of such expenditures, and applying any cost savings against such expenditures to reduce the accompanying revenue requirement, can only be properly performed in a rate case. In light of the fact that the distribution component of rates is based upon cost-of-service studies done years ago, and Staff's desire to limit additional or new deferrals, the Staff recommends that a distribution rate case be conducted at the end of FirstEnergy's MDP to place distribution rates on a current basis. Staff witness Cahaan stated that the presence of a freeze over the past few years has provided a "negative incentive to make needed investment and maintenance expenditures for reliability" (Staff Ex. 3 at 11-12).

OCC argues that, currently, FirstEnergy's ETP distribution rate freeze extends through 2007, with certain exceptions. The permissible exceptions allow FirstEnergy to recover the costs of complying with changes in regulatory laws or regulations related to environmental (distribution-related), taxes, or in the event of an emergency under Section 4909.16, Revised Code (OCC Ex. 3 at 4, Section IV.1). In the proposed RSP, OCC contends that FirstEnergy seeks to add an additional exception to allow FirstEnergy to defer costs incurred to "improve reliability of service." OCC argues that the provision for "reliability improvements" proposed in the RSP clearly exceeds the bounds of the previous exceptions contained in the ETP stipulation. Additionally, OCC believes that Staff witness Cahaan's proposal regarding a distribution rate case improperly supports a breach of the ETP stipulation and a violation of the Commission's ETP order. OCC asserts that neither Staff witness Cahaan nor FirstEnergy provided any evidence as to a decline in FirstEnergy's distribution reliability nor provided any evidence that FirstEnergy cannot meet its responsibilities to maintain a reliable distribution system under its current distribution rates. Furthermore, OCC notes that FirstEnergy has not offered any definition of what constitutes "reliability improvements" that would justify rate increases (Tr. I at 231). OCC recommends that the Commission not approve Staff's proposal for a distribution rate case or Applicants' adjustments for distribution expenditures that circumvent the distribution rate freeze approved in the ETP stipulation.

NOAC and NOPEC point out that distribution service is not a competitive service and is subject to the traditional rate-making process. They argue that the proposed RSP attempts to remove distribution rate increases from the ambit of the traditional ratemaking process set forth in Section 4909.18, Revised Code. NOAC contends that there is no statutory provision that would permit an increase in these rates without a rate case and no statutory authority for the Commission to approve an alternative rate increase. Further, NOAC agrees with OCC that this provision of the RSP violates the terms of the ETP stipulation by permitting FirstEnergy to apply for deferral of costs incurred to improve distribution reliability upon Commission approval of the RSP. NOAC and others argue that it is unreasonable that consumers should be responsible for maintenance failures of the Applicants related to the August 2003 electric blackout that occurred in Ohio and the Northeast.

The Commission believes that it is very important for FirstEnergy to spend the necessary funds to maintain its distribution system to provide reliable service. This has always been the Commission's position. As part of its ETP stipulation, FirstEnergy agreed to maintain its current distribution rates, with certain exceptions, through 2007. There is nothing in the record which persuades the Commission that FirstEnergy cannot fulfill this commitment. Further, we note that in our November 7, 2002 Opinion and Order in Case No. 01-2708-EL-COI et al., *In the Matter of the Commission Investigation into Line Extension Policies*, we approved a cost recovery mechanism for the cost of building new distribution line extensions in FirstEnergy's service territory. There has not been a factual showing that there have been material unforeseen changes to FirstEnergy distribution system or that the costs to maintain reliable distribution service have been far greater than what was anticipated when FirstEnergy entered into the ETP stipulation or since the approval of FirstEnergy's line extension policy. Accordingly, we find that distribution rates can be increased only in a manner consistent with the ETP stipulation. FirstEnergy will have the ability to file an application to increase distribution rates at the end of 2007.

C. Transmission Charges

As for transmission services, paragraph 7 of Section I of the RSP provides that, beginning January 1, 2006, retail transmission, net congestion and ancillary service charges or rates may be adjusted to reflect applicable FERC-approved charges or rates. Pursuant to the RSP, FERC-approved transmission, net congestion and ancillary service charges and rates include charges that the FERC imposes on FirstEnergy directly or costs that the FERC imposes on FirstEnergy indirectly through a FERC-approved RTO, including, but not limited to, RTO administrative charges imposed on FirstEnergy, or surcharges for recovery of lost transmission revenues. However, in all cases, retail transmission, net congestion and ancillary service charges and rates may be adjusted or imposed pursuant to paragraph 7 only if the adjustment is reflected in or permitted by the applicable FirstEnergy or RTO Open Access Tariff filed at the FERC.

OMG and CPS take issue with paragraph 7. They state that, under the Commission's Finding and Order in Case No. 03-1966-EL-ATA et al. (03-1966), the CRES provider schedules and pays for the transmission and ancillary services for retail customers in FirstEnergy's service area. FirstEnergy is then supposed to remit to CRES providers the money it collects under its tariffs for transmission and ancillary services from the customers who shop for whom it no longer supplies such services. OMG and CPS argue that one would expect that, with the end of the legacy rates, CRES providers would charge the retail customer directly for transmission and ancillary services, and FirstEnergy would be relieved from the collection, accounting and paying out of the transmission and ancillary service funds. These parties contend that, if the shopping credits paradigm is still in use during the rate stabilization period, then transmission and ancillary services should be bypassable so that the inefficiency of collecting money just to return it is avoided.

According to OMG witnesses Roach, Merola, and Sharfman, including transmission and ancillary fees in the shopping credit has the potential for over-collection of such costs from the customers that shop (Reliant/CPS Ex. 1 at 11; OMG Exhibit 2 at 18; OMG Exhibit 1 at 13 -15). OMG and CPS believe that, if there is any negative differential between the real price for transmission and ancillary services as billed by the CRES providers to the customer and the theoretical credit that FirstEnergy would incorporate into the shopping credit for the transmission and ancillary service that FirstEnergy did not supply to the customer, the customer could end up paying more for transmission and ancillary service than their actual cost. They argue that the concern of over-collection becomes acute when MISO goes to "Day 2", possibly at the end of this year, and begins to charge congestion fees and offer financial transmission rights. Thus, the OMG and CPS ask for a specific finding that transmission and ancillary service fees for customers who shop will be charged by the CRES provider, and if shopping credits are continued, transmission and ancillary services will be bypassable. OMG and CPS also argue that paragraph 7 has the potential to greatly increase the cost of RSP service. OMG witness testified that, in the MISO Day 2 world, congestion is truly a cost of generation (OMG Ex. 2 at 8-9). Paragraph 7 permits FirstEnergy to pass through to customers all costs associated with congestion fees and financial transmission rights. It is argued that each generation source will have a potentially different cost when landed at a particular sink and that, under the revised application, FirstEnergy Services (FES) has complete discretion to source the market-based standard service offer as it chooses and the FirstEnergy operating companies have the ability to pass these costs on to customers. OMG contends that this creates an incentive for FES to source its competitive accounts with the most efficient sources and source the market-based standard service offer with the remainder since those costs could be passed through.

FirstEnergy argues that the mechanism established by the Commission in 03-1966 for the remittance of transmission revenues to CRES providers eliminates the possibility that customers would have to pay twice for transmission and ancillary services. CRES providers reimbursed by FirstEnergy would not have to include those costs of transmission service in the price they charge. FirstEnergy points out that it also would be possible to reflect the inclusion of these charges in the allowable shopping credit and have the CRES provider charge for these services directly.

Paragraph 7 provides FirstEnergy the ability to adjust charges for retail transmission, net congestion, and ancillary services beginning in 2006. OMG and CPS question the need for FirstEnergy to charge for such service for customers who shop once the MDP has ended, noting certain possible disadvantages to CRES providers and their customers of keeping the mechanism approved in 03-1966 in place after the MDP. We believe this is a matter that CRES providers in this case and FirstEnergy should be able to resolve given the options both OMG/CPS and FirstEnergy have set forth in their briefs. The parties will be directed to meet with each other to determine the best approach to ensure that the shopping customers are not being disadvantaged. The parties that take part in such meetings will be directed to report back to the Commission in this docket on the results of their discussions by the end of the year. Hopefully, by that time there will be more clarity regarding the transmission, net congestion, and ancillary services provided by MISO.

D. <u>Rate Stabilization Charge</u>

The RSP was offered by FirstEnergy in response to the Commission's September 23, 2003 Entry in Case No. 03-1461-EL-UNC, in which the Commission requested that FirstEnergy develop and file a plan for 2005 and beyond that balances three objectives: (1) rate certainty, (2) financial stability for the FirstEnergy, and (3) the further development of competitive markets. The RSP was represented by FirstEnergy to be its determination of the parameters within which it is willing to assume the risks of continuing to supply POLR service at a fixed, market-based generation price, using its generation assets, in the period following the MDP, while still maintaining its financial integrity (FirstEnergy Ex. 1 at 9). The RSC is the charge intended to compensate FirstEnergy for the cost of reserving and supplying that generation (Id. at 18). FirstEnergy proposes to establish a RSC at the same level as the existing GTC

(Section II, Paragraph 2(a)). Applicants set the RSC at the level they believed necessary to maintain price stability for consumers and financial integrity for the companies and it was not intended to reflect cost-of-service principles (FirstEnergy Ex. 1 at 19). The RSC level was based on witness Alexander's judgment as to what would be reasonable and provide consistency and continuity for customers at a stabilized rate (Tr. I at 206).

Many parties to the case objected to the level of the RSC. Their objections were directed to the level of the RSC being determined by Applicants' witness Alexander's judgment, that there was no analysis prepared to arrive at this amount and that FirstEnergy's proposed RSC is not based upon and does not even attempt to quantify the risks FirstEnergy faces. OCC witness Corbin testified that the standard service offer price consumers pay under any RSP should reflect the current generation price plus some adjustment for risk. He offered that the size of the adjustment for FirstEnergy's risk, the RSC, should reflect a balancing of FirstEnergy's needs, such as, compensation for lost opportunity costs; potential price volatility or other market risks from serving as the standard service offer provider; and the customer's needs for stable and/or lower rates (OCC Exhibit 2 at 11-12). NOAC/NOPEC expert witness Frye testified that the RSC was not set as the result of any calculation of risk to FirstEnergy, but rather because it appears to match the expiring GTC and that the amount is an unreasonably high insurance premium to pay for the right to a standard POLR offer from Applicants (NOAC/NOPEC Joint Exhibit 1 at 11). WPS witness Mikulsky argued that FirstEnergy's application actually continues to collect stranded costs in the form of the RSC by calling it a risk premium and by determining its risk premium to equal its GTC. He contends that FirstEnergy's failure to perform studies to justify or support the value of the RSC, or to hedge this risk for the benefits of consumers, makes the charge unreasonable (Mikulsky Testimony at 12). The parties conclude that FirstEnergy has not sustained its burden of proof that its proposed RSC is reasonable.

The Commission recognizes that, in accordance with SB 3, the collection of transition costs through the GTC will terminate on December 31, 2005. The Commission further recognizes that by setting the RSC at the same level as the GTC, FirstEnergy has created the impression that the RSC is a further collection of stranded costs. Notwithstanding that impression, FirstEnergy stated that the RSC represents the price for FirstEnergy to accept the risk inherent in a rate stabilization plan. FirstEnergy was responding to this Commission's request for a rate stabilization plan that balances three objectives: (1) rate certainty, (2) financial stability for the Operating Companies, and (3) the further development of competitive markets. FirstEnergy was clear in its assertion that the proposed RSC was not cost based or the product of extensive studies or analysis as to the appropriate rate for assuming the risk of rate certainty. Company CEO Alexander succinctly stated that the source for the RSC was his judgment based on his years in the industry. The RSC cannot be considered a continued collection of the GTC, as all parties admit that FirstEnergy deserves some premium for its assumption of the risk of rate stabilization. The amount of the premium is linked to FirstEnergy's offer to provide a rate stabilization plan and being the provider of last resort to fulfill its obligations under Section 4928.14, Revised Code. We believe that any proposed modification of the RSC is essentially a rejection of the rate stabilization plan. We believe the RSC is appropriate in context of the RSP with the modifications directed herein.

E. Residential Customer Charge Credits and the 5% Residential Generation Rate credits

The RSP provides that the transition rate credit program rider, as set forth in Attachment 3 of the RSP, for TE, CEI and OE shall cease to be effective on a bills rendered basis as of January 1, 2004. This rider is made up of two credits to residential customer bills. The first is a monthly residential customer charge credit of $1.50 per month for OE customers and $5.00 per month for CEI and TE customers approved by the Commission in Case No. 95-830-EL-UNC. The second is a residential credit to reflect the SB 3 mandated 5% reduction in residential generation rates. However, the RSP states that the monthly residential customer charge credit shall continue to be in effect, provided that the credit shall be reflected as a reduction in the GTC charge effective January 1, 2004 through December 31, 2005 and then as a reduction in the RTC charge and the extended RTC thereafter. Also, the RSP provides that, effective with bills rendered as of January 1, 2004 and through bills rendered through December 31, 2005, the GTC shall also be reduced for residential customers by the full amount attributable to the 5% generation rate credit. After the end of the GTC, the 5% generation credit will be reflected in the RTC and extended RTC (FirstEnergy Ex. 6 at Section I, paragraphs 2, 6, 11, and 12; RSP attachments 3 and 4).

OCC argues that these provisions violate the terms of the ETP. OCC recommends that the current method of accounting for the credits should not be modified. Based on the testimony of OCC witness Pultz, OCC argues that having these credits reflected in the RTC and extended RTC diminishes their value because the amount of regulatory transition costs that FirstEnergy ultimately is to recover is not being reduced by these credit provisions. OCC asserts that applying the credits in this manner effectively lowers the RTC rate and the extended RTC rate and extends the length of time to recover regulatory transition costs. OCC contends that the proposed treatment of the credits does not offer customer the full benefit that they receive currently with the same credits. OCC recommends that the RSP should be modified to continue the treatment of the credits as they are applied currently.

As it stands currently in the ETP, the customer charge credit reduces the customer service charge and is to remain in effect as long as the RTCs are in effect, or with bills rendered on December 31, 2005, whichever occurs last. The 5% reduction reduces the monthly amount of billed generation charge, GTC, and RTC, and is to remain in effect through December 31, 2005. See FirstEnergy Ex. 6, Attachment 3. The Applicants' proposal is to change how these credits are to be applied starting January 1, 2004. Instead of having these credits apply to the customer charge and generation charges, FirstEnergy proposes that they apply to the GTC through 2005, and thereafter to the RTC and the extended RTC. The effect of such changes, as noted by Mr. Pultz, is to lower the GTC and RTC rates, but lengthen the regulatory transition cost recovery periods (OCC Ex. 1 at 12).

The Commission finds that the application of the two credits after 2005 to the RTC, as proposed by FirstEnergy, does diminish the value of the customer charge credit. Under the RSP, the monthly recovery of the RTC is being reduced by the credits; however, the total amount of the regulatory transition costs to be recovered through the RTC does not change. This has the effect of having a credit on bills only to pay for the credit later by the extension of the RTC period (OCC Ex. 1 at 12 and attachment F). The Commission will permit FirstEnergy to modify the accounting of the 5% reduction and customer charge credits as reductions of the GTC and the RTC. However, for residential customers to receive the full benefit of the customer charge credits, the sales targets and time periods for the recovery of regulatory transition costs should not be lengthened or adjusted to account for the RTC rate reduction attributable to the customer charge credits.

F. Regulatory Transition Charge

Under Section II, paragraph 10 of the RSP, upon approval of the RSP, FirstEnergy proposes to accrue and defer interest upon a number of deferrals to be recovered through the Extended RTC (FirstEnergy Ex. 1, Ex. 2 at 9, Section II, paragraph 10) These items are deferred shopping incentives, deferred increases in generation costs and deferred increases in distribution costs for reliability improvements. The increases in generation and distribution costs have been discussed and deferrals associated with those costs have been denied above; therefore, it is not necessary to discuss these deferrals. In addition, credit reductions to the RTC, as discussed in Section E above, were denied, thereby eliminating the need for any discussion as to their application to the RTC.

The ETP stipulation provided that the RTC would be collected until company-specific cumulative sales after January 1, 2001 were reached, or until a company-specific date, whichever came earlier. This date could be adjusted for sales changes if additional time was necessary because economic conditions depressed sales or to amortize the deferrals resulting from more than 20 percent of any class having shopped. FirstEnergy proposed to establish new sales targets based upon sales after January 1, 2004, and new company specific cut-off dates. Under both the ETP stipulation and FirstEnergy's Application, RTC recovery may not continue after December 31, 2010. In the revised RSP, Applicants shortened the time limits for TE and CEI and reduced the kWh collection caps (FirstEnergy Ex. 6, Section II (6)).

NOAC/NOPEC joint witness Frye testified that the original Plan would have increased RTC collections permitted by $1.02 billion (40.6 billion kWh) when compared to the ETP stipulation, and that the Revised Plan reduces the additional RTC collections to $764 million (29.1 billion kWh) (NOAC/NOPEC Joint Ex 2 at 11-12). NOPEC asserts that FirstEnergy made a binding agreement in the ETP stipulation and should not be allowed to renege on any parts of it that may not be favorable to it as originally anticipated. OCC argues that it may have been possible for the terms of the ETP stipulation to produce the same criteria for ending the RTC collection that FirstEnergy is requesting in its Amended RSP (FirstEnergy Ex. 5, Revised Plan at 9-10). However, FirstEnergy has not provided any evidence of this possibility. OCC submits that the

Commission should require FirstEnergy to provide support for the equivalence of its newly proposed criteria for ending RTC recovery to the criteria set forth in the ETP stipulation. If the new criteria add to overall RTC recovery, such added costs should be considered in evaluating the proposed RSP.

FirstEnergy has stated that the additional collections above what was contemplated in the ETP stipulation are appropriate due to lower kWh sales (FirstEnergy Ex. 1 at 11).

Staff witness Hess presented testimony regarding sales targets proposed by FirstEnergy for purposes of its collection of regulatory transition charges. Mr. Hess explained that updated sales targets are required since sales volumes used to create similar targets in FirstEnergy's ETP case are materially different from actual sales volumes for 2001-2002 and forecasted sales volumes for the period 2003-2010. Mr. Hess concluded that the sales targets initially requested by the Applicant in this case are overstated and, if applied, would enable the Applicants to over recover the amount of regulatory assets authorized by the Commission in FirstEnergy's ETP case (Staff Ex. at 2-4).

We find that the ETP clearly allowed for the end date for collection of the RTC to be adjusted for economic conditions. We agree with staff that the actual sales versus forecasted sales issue has been adequately addressed in the revisions made to the RSP outlined in FirstEnergy witness Alexander's Rebuttal Testimony. Accordingly, adjustments to the RTC recovery periods should be allowed. Consistent with this decision, the Applicants shall meet with our Staff to recalculate new sales target levels for recovery of regulatory transition costs.

The Revised Plan provides that the Applicant will accrue and defer interest on the balances associated with shopping credit incentive deferrals effective January 1, 2004. FirstEnergy asserts that this benefit to the Applicant is balanced in the Plan, among other things, by continuing credits to residential customer rates that otherwise would have expired before or during the Plan period, by extending economic development and energy efficiency benefits that otherwise would have expired at the end of the market development period and by providing rate stabilization in a period that could see extremely volatile generation rates.

A number of interveners object to this provision because the Stipulation in the ETP case did not provide for interest on deferred shopping credit incentives. OCC submits that to the extent that the Applicant may complain that the level of shopping, and thus the amount of shopping incentive deferrals, was larger than they anticipated at the time of the ETP stipulation, the other parties to the ETP stipulation could also find elements of the ETP stipulation that worked out differently then they anticipated. GM and NOPEC argue that the request for interest is unreasonable because customers switching to FES contribute to the deferrals.

FirstEnergy witness Alexander offered that incentivized shopping was not intended to deprive the Applicants of funds that would otherwise reduce their capital costs and ultimately the costs of regulated service. These excess deferrals, resulting from excessive shopping credits, have done just that, and the Applicants now need to be compensated for providing this subsidy to marketers. FirstEnergy contends that the Plan does not make any modifications to the ETP stipulation, that it is a new plan that covers the period 2006 through 2008" (Tr. I at 178-79). FirstEnergy argues that the real abrogation of the ETP stipulation came when the Commission declined to adjust shopping credits in order to restrain shopping that is creating excess deferrals, in several cases, including Case Nos. 01-2736-EL-UNC, 02-2877-EL-UNC and 03-1461-EL-UNC (Tr. I at 188-89). FirstEnergy asserts that the original ETP stipulation expressly provided that shopping incentives "may be adjusted in subsequent years as deemed appropriate by the Commission to minimize deferrals" (OCC Ex. 3 at 7) and, because the Commission did not do so, the result of over-incentivized shopping has been to "create over $500 million of deferrals over and above what should have been deferred. . . ." (Tr. I at 182). FirstEnergy concludes that the ETP did not contemplate this $500 million of deferrals, and the fact that it made no provision for interest on a balance that was not contemplated to exist is not a reason for the Applicant to forego interest when designing a new plan, extending for a longer period, and likely to result in even greater deferrals.

NOPEC argued that FirstEnergy should be denied interest on deferrals because of the merger with GPU in 2001. NOPEC asserts that there is no tracking mechanism allocating dollars from GPU ratepayers to pay off GPU debt. FirstEnergy offers that any debt associated with the GPU merger is retired by "cash that was generated from that specific GPU operating company," regardless of whether or not there is a tracking mechanism (Tr. III at 179).

OCC also objected to the interest provision on the basis that an interest rate that is equivalent to the overall cost of long-term debt for each distribution company is not appropriate. FirstEnergy submits that the rate is entirely appropriate because the associated borrowings are in fact long-term, extending beyond a year.

We believe that the collection of interest on the shopping credit deferrals is an appropriate part of the overall RSP. We find that the merger with GPU is irrelevant to this proceeding and that no party has offered a more appropriate interest rate than that proposed by the Applicant. The ETP stipulation provided for the Commission to adjust the shopping credit incentive to minimize deferrals. Shopping has increased to the point where the need to minimize the detrimental effect of large deferrals is established, but must be balanced with the need for marketers to meet contractual responsibilities that were based on the anticipated shopping credit levels. Therefore, the Commission considers the granting of interest on the shopping credit deferrals, as of January 1, 2004, is within the Commission's discretion to minimize the impact of deferrals on FirstEnergy as authorized in the ETP. The Applicant's proposal for deferral and collection of interest charges on shopping credit incentives through the RTC should be allowed.

Therefore, FirstEnergy's request to change the amortization schedules for regulatory transition costs (not including deferred shopping credit incentives and other deferrals authorized herein) should be approved, as revised, effective January 1, 2004. FirstEnergy should, consistent with the Revised Plan, accrue and defer interest on the deferred shopping credit incentives and the accumulated deferred interest (i.e., compounding on a monthly basis) effective January 1, 2006. Recovery of the deferred shopping credit incentives, and deferred interest, should be accomplished through the extended RTC charge through the actual recovery period for such deferred costs, but no later than through usage as of December 31, 2010; termination of the Revised Plan will not affect recovery of these deferrals, the RTC charge, or the extended RTC charge; and FirstEnergy should begin amortizing the costs being recovered through the extended RTC charge on the effective date of the extended RTC charge on a dollar-for-dollar basis as the corresponding revenue is recognized.

G. Shopping Credits/Avoidable Charges

Shopping credits were the prices to beat that become the reference point for customers to determine if shopping can reduce their electric bills. Shopping credits are a deduction against the Applicants' own generation charges on the bills of customers who switch to a competitive supplier for their generation service. FirstEnergy has proposed shopping credits for the years 2006-2008, which, in the context of the post-MDP years, may better be characterized as avoidable expenses.

In FirstEnergy's first filing of the RSP, the shopping credit offered was *g* plus 65% of RSC, if suppliers entered into a binding three-year contract with a governmental aggregator or commercial/industrial customer and provided the required notice (FirstEnergy Ex. 2, Sec. II, paragraph 2 (b)). In FirstEnergy's submission of the Revised RSP, an expanded number of shopping credit options was delineated (Sec. II, paragraph 2 (b)(1)). Under the Revised Plan, governmental aggregators or commercial/industrial customers who enter into binding contracts with a CRES provider for the period of either 2006 through 2008, 2007 through 2008 or just the year 2008, would receive a shopping credit of *g* plus 65% of RSC in 2006, *g* plus 75% in 2007; and *g* plus 85% in 2008. If customers under these options returned to the Operating Companies for generation service during those contract periods, the charge for generation would be priced at a variable market price for a period of six months, defined as "the average of the highest purchase power costs incurred by any affiliate of FirstEnergy to serve any of its customers during the applicable month and the remaining term of the Plan" and thereafter they would be served under the standard offer rate set forth in the Revised Plan (*Id.* at 2(b)(2).) The Revised Plan also offered governmental aggregators and commercial/industrial customers the option of *g* plus 100% of RSC as the shopping credit (*Id.* Sec. II, 2(b) (2)). Any customer opting for this higher shopping credit that returned to the Operating Companies for generation service during the Plan period would be served under a variable market price rate as described above (*Id.*) The proposed Revised Plan froze the 2005 shopping credits at the same level as 2004 (Sec. VIII, paragraph 6) and generally capped shopping credits for 2006 through 2008 at the existing 2004 level. For rate schedules affected by the cap that do not have 20% shopping, the Revised Plan made market support generation (MSG) available to those customers at below market prices, until such time as 20% shopping is reached (Sec IV, paragraph 4.) In addition, any difference between the shopping credit cap and *g* plus

100% of RSC would be used to reduce the interest charges to be deferred during the applicable period in 2006 through 2008, as discussed above (Sec. II, paragraph 2(b)(2).)

FirstEnergy submits that there is no reason to believe that shopping will diminish if the 2004 shopping credit remains in effect in 2005. The main reason being that the shopping credits in effect today are higher than those in effect during 2003. At the 2003 shopping credit levels, there was considerable, over 900,000 customers, shopping in all of the rate classes of the Applicants. The Applicants note that the ETP stipulation provides:

> "If more than a 20% shopping level is attained for the commercial and industrial classes determined on a company by company basis, the incentive will not be further increased for such class and may be adjusted in subsequent years as deemed appropriate by the Commission to minimize deferrals . . . but such adjustments shall not result in a shopping incentive that would result in customer switching falling below 20%. If the shopping level for the residential class determined on a Company by Company basis exceeds 20%, then the incentive may be adjusted in subsequent years as deemed appropriate by the Commission to minimize deferrals . . . but such adjustments shall not result in a shopping incentive that would result in customer switching falling below 20%" (OCC Ex. 3, p. 7).

The Applicant concludes that shopping has reached such levels where it is now appropriate to adjust the shopping credit levels in the ETP to minimize deferrals.

The intervening marketers, governmental aggregators and OCC argue that FirstEnergy's proposal to allow the 2004 shopping credits to remain in effect, and not be increased during calendar year 2005, would likely have a negative impact on shopping. The ETP stipulation at V.2 provided for annual increases in the residential shopping credits through 2005, unless adjusted by the Commission. Under Section VIII.6 of the RSP, the 2005 increase will not occur if the RSP is adopted as filed and revised. OCC witness Pultz noted that this would occur even if the company was given notice of termination of the RSP by January 1, 2005 (OCC Ex. 1 at 10). OCC witness Pultz further testified that FirstEnergy's proposal would deny shopping customers approximately $15 million in increased shopping credits. (Id).

Mr. Frye, the jointly sponsored witness of NOPEC and NOAC, testified that governmental aggregation groups entered into long-term contracts with suppliers on the assumption that the ETP stipulation levels would be maintained, and that suppliers based contract decisions on this assumption when they entered into long-term power contracts. (NOAC/NOPEC Joint Ex. 1 at 23).

There is general agreement that the competitive retail generation market in Ohio will not be fully mature and robust as of January 1, 2006. Staff witness Cahaan observed that "a well-functioning and competitive wholesale market is a necessary precondition for an efficient retail market," and that "such a market does not exist at present" (Staff Ex. 3 at 3). OCC witness Corbin and Cleveland witness Konicek testified that the competitive retail electric generation market is not fully developed in FirstEnergy's territory (OCC Ex. 2, p. 5; Clev. Ex. 1 at 6; Tr. VIII at 50, 52). The Commission expressed its concern, that lowered shopping credits would have a negative impact on shopping, when it rejected FirstEnergy's request to lower the 2004 and 2005 shopping credits, in Case No. 03-1461-EL-UNC, Entry dated September 23, 2003, denying the adjustment of 2004 shopping credit and postponing consideration of the 2005 shopping credits to this proceeding. There has been no further evidence offered that the shopping or deferral levels have dramatically changed since that time. We believe that the linkage of the 2005 shopping credit to the RSP is inappropriate. As Mr. Alexander explained, "[t]he Plan represents FirstEnergy's determination of the parameters within which it is willing to assume the risks of continuing to supply POLR service to its Ohio customers at a fixed, market based generation price, using its generation assets *after the end of the MDP*, while still maintaining its financial integrity" (FirstEnergy Ex. 1 at 9, *emphasis added*). Freezing the 2005 shopping credit at the 2004 level *before the end of the MDP* cannot be rationalized, as asserted by the company, as an integral part of the RSP. We believe the company's proposal for modifying the ETP stipulated annual increases in the shopping credits for the year 2005 is not reasonable. The requested adjustment would have unknown impacts on the benefits obtained from shopping commitments and on the levels of shopping in 2005, before the RSP period would even begin. Marketers and aggregators have numerous contractual responsibilities that will emanate from the RSP. Maintaining the ETP shopping credit levels will provide a smoother transition into the RSP. We find that the company has not provided sufficient justification to adjust the ETP. The 2005 shopping credit values should be derived in accordance with the ETP stipulations. The values should comfort with attachment 2 of the ETP stipulation and attachment 3 of the ETP supplemental materials. In order to apply those average increases, FirstEnergy should adjust each shopping credit rate block contained within the existing tariffs from the current levels by the appropriate percentage increase derived from the attachments.

WPS, Dominion, GMEC and OCC argue that FirstEnergy's shopping credit proposal would implicitly deny direct and non-governmental aggregation shoppers the opportunity to shop. Customers in aggregation programs that are not governmental aggregation programs, and customers who have individually shopped with a supplier, do not receive an enhanced shopping credit. These categories of customers would only receive "g" as a shopping credit (Tr. I at 209). FirstEnergy witness Alexander stated that shopping is improbable without the enhanced shopping credit, when the shopping credit is "g" (Tr. I at 209). Thus, it is asserted, that direct and non-governmental aggregation shoppers are essentially denied the opportunity to shop under the RSP. These parties conclude that this is an unjustified discrimination against residential customers who are not participating in governmental aggregation programs that meet FirstEnergy's requirements.

Aside from FirstEnergy's rationale for the limitation of access to the enhanced shopping credit, it is clear that the notice and term requirements in the RSP would make direct sales incompatible and inefficient. We fail to see the difference between governmental and non-governmental aggregation. Allowing non-governmental aggregators, who meet the capacity, credit, notice and term requirements of the RSP, to have similar access to the enhanced shopping credit would clearly benefit competition. It would also provide an opportunity for current direct sales customers to be "aggregated" and not be disenfranchised by the RSP. We, therefore, direct that non-governmental aggregators be afforded the same access to credits as governmental aggregators.

FirstEnergy submits that it has designed the shopping credits included in the Revised Plan as part of a comprehensive package, that the package balances the interests of many parties, and that selective adjustments to specific Revised Plan provisions should not be considered an option. The Applicant contends that there is no reason to increase the shopping credit levels included in the Revised Plan, as they are reasonable as proposed, will support significant shopping during the period 2005 through 2008 and limit the deferral costs to customers.

According to FirstEnergy, the Revised Plan offers a number of shopping credit options. They apply to eligible customers who enter into contracts for the 2006-2008 period, the 2007-2008 period, or just for 2008. If an eligible customer enters into a three-year contract, the shopping credit would be "g" plus 65% of RSC for the first year of the contract, "g" plus 75% of RSC for the second year, and "g" plus 85% of RSC for the third year. The shopping credits for a two-year contract covering 2007 and 2008 will be "g" plus 75% of RSC in the first year, and "g" plus 85% of RSC in the second year and also for one-year contracts for 2008 (Tr. X at 67-68, Sec. II, paragraph 2 (b)(1)). The Revised Plan also offers the option of *g* plus 100% of RSC as the shopping credit for 2006 to 2008 period, but any customer that returns to the Operating Companies for generation service during the Plan period would be served under a variable market price rate for the remainder of such period or until the customer selects another supplier (Sec. II, paragraph 2(b)(2)). The Revised Plan includes a provision that limits caps all 2006 to 2008 shopping credits at existing 2004 levels to recognize what the Applicant considers to be substantial amounts of shopping already occurring at this shopping credit level. For those rate schedules affected by this shopping credit cap that do not have 20% shopping, The Revised Plan makes MSG available to customers in rate schedules affected by this shopping credit cap that do not have 20% shopping customers until 20% shopping is achieved (Sec IV, paragraph 4). Finally, the Applicant claims that the comprehensive package is completed by the provision that any difference between the shopping credit cap and *g* plus 100% of RSC would be used to reduce the interest charges to be deferred during the applicable period in 2006 through 2008, thereby effectively returning such amounts to customers (Sec. II, paragraph 2(b)(2)).

FirstEnergy offers that as of September 30, 2003, more than 900,000 customers within the Applicant service territories shopped. This was accomplished at 2003 shopping credit levels and the Commission allowed the overall shopping credits applicable in 2004 to increase from the prevailing levels in 2003, in accordance with the ETP. FirstEnergy argues that, with no evidence that generation costs will increase during the Plan period, the proposed level of shopping credits will not inhibit shopping from continuing at least at those levels. FirstEnergy states its belief that marketers and aggregators have enjoyed the benefits of market subsidies since they commenced providing generation service in the Applicants service territories and that the Plan does not eliminate these subsidies, but eliminates additional incentives in a market that is already supporting significant shopping. Further, the Applicant states that simply increasing shopping credits will not guarantee that shopping activity will increase, or that customers will save any money. FirstEnergy contends that no party in this proceeding who advocates another increase in shopping credits demonstrated any direct correlation between levels of shopping credits and either shopping activity or savings. FirstEnergy postulates that this is due to the fact that there is absolutely nothing that requires marketers and aggregators to pass any portion of such increases on to customers.

The Revised Plan provides that the enhanced shopping credits described above would be capped at the shopping credits in place for 2004, plus any riders or increases in "g" approved by the Commission under the Revised Plan (Sec. II, paragraph 2(b) and Attachment 5). According to FirstEnergy, the cap would affect less than half of the Operating Companies' rate schedules and would not apply to any of the CEI or Toledo Edison residential tariffs and to only one Ohio Edison residential tariff. The cap primarily affects small commercial rates and some industrial rates (Tr. X at 136). Applicant witness Alexander explained that the shopping credit caps were included in the Revised Plan "to recognize the rate design principles that are embedded in the current rates and to avoid the creation of false markets during the plan period that would not be sustainable over the long term" (FirstEnergy Ex. 5 at 3). The difference between the maximum shopping credit and "g" plus 100% of the RSC for the eligible customers who are subject to the cap and shop would be used to minimize the amount of additional deferrals that will be created as a result of the shopping credit incentives which witness Alexander emphasized that current deferrals associated with these incentives are approaching a half billion dollars (Tr. I at 182). FirstEnergy concludes that there is nothing in the record to support a finding that the shopping credits in the Revised Plan are too low, or that the Revised Plan will adversely affect competition.

The marketers, governmental aggregators and OCC argue that FirstEnergy's proposal to set the enhanced shopping credits at the lower of little "g" plus RSC or a cap based on the 2004 shopping credit levels will severely limit shopping in the future and greatly reduce or eliminate current levels of shopping in some significant rate categories (For example, WPS-ESI Ex. 3 at 2-4). They argue that FirstEnergy's proposal would likely eliminate shopping in the CEI and TE residential and small commercial classes. Cleveland/WPS witnesses Giesler and Higgins testified that if any shopping credit from the market development period were to be carried forward, it should be the 2005 shopping credit values or the higher of little "g" plus RSC, in order to provide stability to the 2005 through 2008 marketplace. This approach is more likely to sustain shopping at current levels, promote further market participation, and enable market participation by CEI residential customers (WPS Ex. 2 at 3; Cleveland/WPS Ex. 1 at 13-14; Giesler Surrebuttal at 3). NOAC/NOPEC witness Frye testified that the 2005 shopping credits in the ETP should be the minimum credits for 2006-2008 (NOAC/NOPEC Ex. 2 at 14). Dominion witness Butler proposed, as one alternative, shopping credits with 2005 levels as a starting point and added 5% to the 2005 ETP values to arrive at proposed shopping credits for 2006-2008 (Dominion Ex. 1 at Attachment G-DOM, columns (a) and (b)). GMEC witness Chernick's recommendation also concluded that there should be minimum shopping credits by customer class for the years 2006-2008. The minimum should be the credits the Commission adopts in this case for the year 2005 (GMEC Ex. 1 at 49).

We believe that the Revised Plan must be viewed as an avoidable expense model for the post-MDP; therefore, the conceptual proposals that relied on minimum levels of shopping credits are not functional in this paradigm. Shopping credits existed to promote and maintain shopping, and provide an incentive for marketers and suppliers to compete in the Operating Companies' service territories. The success of shopping credits and MSG in achieving this purpose may best be measured by the extent of shopping in the FirstEnergy area. Most, if not all, rate schedules for all the Operating Companies have achieved 20% shopping; the total number of customers shopping is over 900,000. However, the cost of this program has been increasing deferrals and a market dependent on incentives. We agree with FirstEnergy that the market subsidies have benefited the marketplace, but to a greater extent have largely benefited the marketers and aggregators that have provided generation service in the Operating Companies' service territories. The Revised Plan does not eliminate these subsidies, but does eliminate the additional incentives in a market that is already supporting significant shopping. We further agree that simply increasing shopping credits alone will not guarantee that shopping activity will increase, or that customers will save any money. The FirstEnergy RSP offers a range of avoidable expense of 100% to 65% of the RSC, depending on timing, duration of contract and POLR cost upon return to the system. We do, however, believe the 2005 shopping credit discussed above should be utilized to determine the avoided cost cap for the RSP. The 2005 shopping credit by class would be more appropriate as the cap since it would further stabilize rates during the transition into the Plan. We find that the shopping credit/avoidable expense model in the Plan, as modified, furthers the Commission's stated goals of rate certainty, financial stability for the Applicant and promotion of the market.

The Revised Plan's proposed POLR service, depending on the shopping credit level, requires shoppers to return, for either six months or possibly for the remaining term of the Plan, to the average of the highest purchase power costs incurred by any affiliate of FirstEnergy to serve any of its customers. Applicant witness Alexander clarified that customers opting for the 100% credit for the three-year period of the Plan would have to stay at market prices only until they select a new supplier in a manner consistent with the criteria set out in the Revised Plan for enhanced shopping credits, and provide notice by the next available date under the Revised Plan (Tr. X at 153-154). The Revised Plan further requires that aggregation customers "must be informed" of this return pricing (FirstEnergy Ex. 5; Revised Plan at Section II, paragraph 2 (b)(2)).

FirstEnergy submits that the issue with returning customers is that it must arrange in advance to buy all of the power it is obligated to supply or pay the market price. The shopping credit allows percentages of the RSC to be avoided, depending upon the length of time the customer is committed to obtain power elsewhere. When that commitment is breached, FirstEnergy states that it must once again be the supplier, at prices it does not control. The Applicant contends that it is at risk that customers who have avoided a significant part of the RSC will return nonetheless. FirstEnergy offers that they are more likely to do so when prices are high than when they are low (Tr. I at 213). The Applicant believes that it must be kept whole for potential costs and compensated for the risks associated with the obligation to provide POLR service. Applicant witness Alexander further explained that the cost would only be known and calculated when the customer returned, and that it would be the price on an hourly basis, averaged over the time frame (Tr. X at 160-64). Mr. Alexander stated that the Applicant would "look at the hourly prices that FirstEnergy has for purchased power and its costs for the entire month and take those prices, highs and lows, and average them together and then compare that to determine that price, divide that by the total number of kilowatt hours and that becomes the price per kilowatt hour" (Tr. II at 155-56). FirstEnergy declares that the purpose of the return mechanism is not to make money for the Applicant, but to recover the costs imposed on the system by returning customers. (Id. at 156.)

The marketers, aggregators and OCC opposed this arrangement for returning customers. WPS argues that FirstEnergy could justify either the RSC or market prices to returnees for some period of time, but that this proposal appeared to be designed to kill shopping. WPS submits that there is no justification for consumers to pay FirstEnergy the RSC then also be subjected to the then-current market prices upon their return from shopping. WPS contends that all returning shoppers should return to a fixed price standard offer POLR service with any Commission-verified incremental costs above tariff rates incurred by FirstEnergy to serve returning customers recovered through the RTC, or an Extended RTC. The margin when customers return and market costs are below tariff rates could be used to reduce the RTC or Extended RTC deferrals. WPS stated its belief that this would make FirstEnergy whole through a non-bypassable charge, and keep customers whole by making the recovery a two-way street. NOAC/NOPEC witness Frye testified that shopping would be discouraged as potential savings would be overshadowed by the fear that in the event of a supplier default, returning customers would pay the highest price incurred by any FirstEnergy affiliate for the remainder of the term of the RSP (NOAC/NOPEC Ex. 2 at 9). NOPEC believes that returning customers should pay no more than the incremental cost of purchased power for such customer, meaning that customer's load in the applicable operating company service territory where the customer resides for a limited period of time, not greater than six months for customers under the little "g" plus the 100% RSC option (NOAC/NOPEC Ex. 2 at 7). OCC stated its position that the RSP should be modified to ensure that only prices related to FirstEnergy's Ohio service territories and only costs that reflect the actual incremental cost of power to supply the particular customer that returns to FirstEnergy are used. Staff witness Cahaan, during cross-examination on the original plan, testified that return pricing should be the incremental price of providing power to the returning customer (Tr. IV at 208-209).

The Commission believes that the issue of the POLR price for returning customers is crucial for marketers and aggregators to offer competitive products and for the appropriate risks to be imposed on those customers. We believe the relevant market for analyzing and specifying market pricing is that served by the EDU. If it were the FirstEnergy system, then all pricing for all customers on the FirstEnergy system should be the same, and situational factors that affect pricing for customers should be reasonably similar across load serving affiliates of FirstEnergy. That is not the case. For example, the FirstEnergy operating companies in Ohio are members of the MISO, while the operating companies serving load in Pennsylvania, New Jersey and New York are part of PJM. The fact that FirstEnergy has organized its purchasing function such that it cannot separate purchasing for customers in each of its load serving affiliates does not justify the result. Relevant market pricing for customers returning to generation service provided by the EDU needs, therefore, to be a market-based price that is relevant to customers served by each EDU. In addition, the Commission is concerned that the pricing approach proposed by the Applicants is too vague, and not transparent. In order for the price to be transparent, the Applicants would need to be subjected to audits of their purchases, which could then give rise to further controversy and potential challenges. The Commission believes that a better approach would be to base come-back pricing on a publicly available market pricing mechanism that can easily be verified, and which can be discovered directly by returning customers. To the extent practical, the Applicants should base pricing on a portfolio approach, using monthly forwards to purchase blocks of power. The Commission believes that such a mechanism must be differentiated according to whether MISO Day 2 is yet to be implemented, or whether it is in place. FirstEnergy should submit to the Commission, within 90 days of this order, a new pricing plan for returning customers that incorporates these concepts. In regard to the provision of the Revised Plan that customers must be informed of the cost of returning to the FirstEnergy system, the PUCO's rules already require that governmental aggregators provide written notice to prospective customers that they could be charged rates upon returning to the electric utility that are different than rates charged other customers served by the utility. Rule 4901:1-21-17(A)(6) O.A.C. The specifics of the notice may best be developed by marketers and aggregators with PUCO Staff input.

NOPEC expressed its concern that under the Revised Plan, MSG will only be allocated to customers within a rate class that is affected by the shopping credit limitation (FirstEnergy Ex. 6 at Section IV (4)). In the residential classes, only OE Rate 10 is affected by this limitation and eligible for the MSG. NOPEC argues that if there is 0% shopping for residential customers in the TE and CEI service territories, those TE and CEI customers will never be eligible for any MSG under the Revised Plan (NOAC/NOPEC Joint Ex. 2 at 12). It is noted that FES sales count towards meeting the 20% level (Tr. Vol. III at 84). NOPEC concludes that the failure to offer MSG in CEI and TE service territories while offering it in OE service territories is unlawful and discriminatory under Ohio law.

The Commission notes that Applicants' witness Alexander confirmed that the primary residential classes on TE would never receive any MSG even if shopping were to be below 20% (Tr. Vol. X, at 199). The Commission is concerned that the impact of the RSP on shopping cannot be determined at this time, and there is a definite benefit to the retention of at least minimum shopping levels as the market develops. The supply of MSG when the shopping levels would fall below 20% would ensure those minimum levels of shopping. Section IV (4) of the Revised RSP should be modified to eliminate the restriction as to MSG being provided to those rate classes that fall below 20% shopping only when the shopping credit limitation applies. First Energy should submit its methodology for the supply of MSG within 90 days of the date of this order. The process should incorporate the terms and conditions for the provision of MSG as delineated in the ETP; however, it should include how the process will harmonize with the contractual and notice requirements in the RSP.

Parties also criticized the Plan provision that requires customers to notify FirstEnergy a year in advance if they are opting out of the Plan and taking generation service from an alternative supplier. NOPEC contends that since the date for having a three year contract in place for the period of 2006-2008 is set in the Revised Plan at December 31, 2004, this requires an electric supplier to commit as many as three years in advance to supply the requirements of the aggregated group in 2008 and is unreasonable. FirstEnergy submits that the one-year notice requirement is necessary to make the Plan work. We believe that in order to offer price certainty through the Plan, FirstEnergy must have ample time to procure and manage the wholesale supply portfolio. The number of customers choosing not to take service from the Operating Companies is also critical information. FirstEnergy must be allowed to factor loads into the procurement strategy and if purchases can be avoided, have ample time to commit these supplies elsewhere and time the sale so as to take advantage of upturns in the market. The Commission finds that Applicants should be allowed to properly manage their risk; the provision delineating the advance notice should not be modified.

H. Energy Efficiency and Economic Development

As part of its RSP, FirstEnergy has stated that it will continue to support energy efficiency improvements by making annual grants available of $500,000 per year by each of OE and CEI, and $250,000 per year by TE, commencing January 1, 2006 through December 31, 2008. The methods for distribution and administration of these programs as currently in effect will be continued, unless the Applicants and the OPAE, as the administrator of the program, otherwise agree (FirstEnergy Ex. 6 at 10).

Additionally, the RSP provides that, commencing January 1, 2006 through December 31, 2008, the Applicants will make available for economic development activities throughout their respective service territories up to $5 million annually during the term of the RSP. Of this amount, OE and CEI will each make available up to $2 million in any calendar year, and TE will make available up to $1 million in any calendar year. The funds will be made available for projects that expand or upgrade customer facilities, or that increase jobs at the customer's facility(ies) in FirstEnergy's service territory. The funds may also be used to support economic development activities generally of organizations engaged in such activities within the Applicants' service territory (Id).

Citizen Group argues that FirstEnergy's support for energy efficiency improvements of $1.25 million a year under the RSP is far less then the $5 million a year FirstEnergy provides under the ETP for energy efficiency programs. Citizen Group requests that grants of $4 million dollars a year should be provided by each OE and CEI and $2 million per year by TE. The yearly total for FirstEnergy would be $10 million, or the sum of $30 million for three years, beginning January 1, 2006 and lasting through December 31, 2008.

OPAE supports FirstEnergy's proposed grants for energy efficiency programs during the RSP period. It states in its brief that it is now serving as the administrator of the energy efficiency programs that will help low-income customers cope with unaffordable electric bills. OPEA asserts that it is in a position to ensure that assistance is provided to those most in need through an expanded network of nonprofit agencies.

The Commission has long supported utility efforts regarding energy efficiency and economic development programs, finding that these programs are in the public interest. In its original RSP proposal, FirstEnergy offered to provide $1.25 million per year for three years for energy efficiency programs and $5 million over the three-year RSP for economic development activities (FirstEnergy Initial Application at 9). In its revised Plan, FirstEnergy provided an additional $10 million to economic development activities as part of its stipulation with OPAE and others. Although OPAE and FirstEnergy have agreed on the amount of funding to be provided for these programs, other consumer and low-income groups have expressed their concern with the substantial reduction in funding for energy efficiency programs. Inasmuch as FirstEnergy has proposed reducing funding for energy efficiency programs for the period of 2006 through 2008 from $5 million to $1.25 million per year, we believe that the $10 million of additional funding FirstEnergy has agreed to provide should be divided equally between energy efficiency programs and economic development activities. This should help lessen the impact of reduced funding for energy efficiency programs during the RSP period. Accordingly, as part of the RSP, the Commission directs that modifications be made to the funding of these programs as set forth above.

I. Plan Termination

Section V of the RSP states that the Commission may decide to terminate the RSP on its own initiative (or at the request of any petitioner) effective on any January 1 of the Plan tenure. Such termination, however, "shall not occur sooner than 12 months after the Commission's decision to terminate" (FirstEnergy Ex. 2 at Section V.4. at 11). Section VI of the RSP details how FirstEnergy may terminate the RSP. The RSP, as originally filed in Section VI, allowed FirstEnergy to terminate the Plan if it shut down, retired, or abandoned more than 250 MW of generation for environmental reasons. Staff witness Cahaan testified that this provision negated the benefits of certainty the Plan provides for consumers (Staff Ex. 2 at 7-8). The Revised Plan Section VI makes the Applicant's right to terminate subject to a prior Commission determination "that such shutdowns would materially or adversely impact the Operating Companies' ability to provide service under the rates, terms and conditions of this Plan or obtain financing on reasonable terms."

OCC was the only party to object to the Section V provision requiring 12 months notice to terminate the RSP. OCC argued that this provision was unsupported in the application and unreasonable and, that circumstances at the time could dictate a more immediate termination of the RSP. We believe that demands of the market and the regulatory process would necessitate a one-year period to transition from the RSP.

Objections were raised to termination pursuant to Section VI by WPS, OCC, NOPEC, GMEC and Dominion. WPS argued that allowing FirstEnergy to terminate the RSP, upon the environmentally-related loss of 250MW of its generation, defeats supply reliability and price stability under the RSP. According to WPS, the section shifts FirstEnergy's risk to consumers and limits the Commission's discretion. GMEC contends that there should not be early termination of the Plan, whether by the Applicants or by the PUCO, unless PUCO termination is for an extraordinary circumstance. OCC and the other parties that raised objections stated that the Revised Plan only gives the Commission the authority to determine whether a shutdown would materially or adversely impact FirstEnergy's ability to provide service under the RSP. Once a determination is made that the shutdown either materially or adversely affects FirstEnergy, FirstEnergy may terminate the RSP, even if the adverse impact on FirstEnergy is minimal (Tr. Vol. X at 184-85). Thus, the Commission has no authority to reject the termination request once a determination has been made regarding the potential effects on FirstEnergy from such a plant closure. OCC asserts that the Commission needs complete discretion and authority over whether a termination request by FirstEnergy should be accepted.

FirstEnergy maintains that if the Commission does not want the termination to occur, it need only find in the first instance that the result of the shut-down is neither material nor adverse. FirstEnergy argues that the Commission can find that any such effect is de minimus, and, therefore, meets neither criteria as meaningfully interpreted, and foreclose the Applicant from terminating the Plan.

We find that the Revised Plan's termination provisions are reasonable as clarified in the record of this case. The criteria for termination, as we interpret the Plan, would require 12 months prior written notice and the filing of an application with the Commission that establishes a clear nexus between the environmental action(s) and the FirstEnergy decision to retire or shut down the units. The Applicant would need to further establish to the Commission's satisfaction that the withdrawal of such generation from FirstEnergy's portfolio, be it by shut down, a forced retirement, or abandonment, materially or otherwise significantly adversely impacts the FE Companies' ability to perform under and within the constraints of the RSP. Since, under the RSP, the final decision, and the process and procedure of the case, will be subject to the discretion of the Commission, the Commission finds the termination process reasonable.

J. <u>Corporate Separation</u>

In the Revised Plan, FirstEnergy requests the Commission to extend the waiver of the Section 4928.17, Revised Code, requirement that the Applicants corporately separate, until 12 months after the Commission terminates the Plan or until December 31, 2008, whichever occurs earlier (Revised Plan, p. 14 and Section VII, paragraph 2). During the ETP Case, the Operating Companies filed an interim corporate separation plan ("ICSP") pursuant to Section 4928.17(C), Revised Code, with the rationale being that it would be financially impractical and virtually impossible to unwind the financial obligations and associated liens on the Operating Companies' property and to fully separate the ownership of the Operating Companies' generating assets prior to January 1, 2001 (ETP Order, p. 20). The ICSP proposed an alternative in which the utility services, competitive services and shared services would be functionally separated into three business units. It also included a code of conduct and accounting plan wherein the interactions among these three units were outlined, as well as a time line that established an estimated date of December 31, 2005, to transfer the Operating Companies' generating assets. The Commission, for good cause shown, approved the ICSP in consideration of the unique circumstances faced by the companies (Id. at 26, 27). FirstEnergy claims that the extension of the ICSP and related waivers, as requested in Section VII.2 of the Revised Plan, will save the Operating Companies the time and expense associated with retiring debt early, unwinding lease arrangements, and obtaining regulatory approvals. The Applicants contend that they have made a concerted effort to retire debt related to the generating assets and that they have not been able to retire the debt as quickly as anticipated, due to the fact that economic conditions have changed since the filing of the ICSP. FirstEnergy offers that Section VII.2 of the Revised Plan simply seeks to extend this approval through a period ending no later than December 31, 2008, thus leaving the existing corporate structure, code of conduct, accounting practices, and other terms and conditions included in the ICSP unchanged during this period. According to the Applicants, the extension of the ICSP maintains the current operating structure and allows FirstEnergy Solutions (FES) and the Applicants to continue to conduct business during the RSP period in the same way they have been doing business in the market development period (Tr. Vol. I at 85). Applicants conclude that, since there will be no significant change in operating conditions, it is imprudent and unnecessary to require the Operating Companies to devote time and resources to corporate separation activities that have no substantive effect on market conditions.

NOPEC, WPS, NOAC and the Marketers take the position that the Operating Companies have not shown that good cause exists to continue the ICSP and that full corporate separation is required. In general, it is argued that the record in this case shows that the nature of the relationship between Applicants and FES is such that the corporate separation safeguards envisioned by the Legislature in SB 3 need to be observed to preserve fair competition, that the RSP period requires the enforcement of a strong code of conduct and full corporate separation and that the post market development period design will be flawed and rendered ineffective if full corporate separation is not established. These parties point to the fact that FES has more than 300,000 customers in Ohio, that the majority of FES' retail electric sales are made directly to customers or aggregators in the State of Ohio and that the vast majority of FES total national competitive direct retail sales are in Applicants' service territories (Tr. Vol. II at 92-94). This significant market share of FES in Applicants' service territories, and the fact that such in-territory sales constitute the vast majority of FES' national retail electricity sales, are offered as evidence as to the need to deny the waiver request.

The ETP order referred to two types of waivers. One was the financial separation due to financial entanglements involving the generating assets of FirstEnergy. There is a second waiver that permitted a general waiver from full structural separation as the Operating Companies had constructed programs that, to the extent reasonably practical, met the structural requirements of Section 4828.17(A)(1), Revised Code, (ETP Order at 26, 27). In this proceeding, the Applicants are requesting an extension of those waivers. If the RSP, as modified by this order is implemented, the Commission believes an extension of the waiver in regard to the divestment of the generating assts should be granted as it would be beneficial to minimize the expense associated with retiring debt early, unwinding lease arrangements, and obtaining regulatory approvals. In consideration of the economic conditions that inhibited the retirement of the debt associated with the facilities, we find that FirstEnergy has shown good cause to extend the waiver in regard to the divestment of the generating assets. It should be noted that, if the company does not implement the RSP, as modified by this order, then full separation should be established.

In regard to FirstEnergy's request for an extension of the waiver for anything in the corporate separation plan that conflicts with any rule, order or tariff, the attorney-examiner at the hearing specifically requested that the company in its brief describe which waivers from the ETP case are at issue, including the specific areas where the Applicants will not be in compliance with the rules (Tr. XI at 196). Applicants have had over three years to develop a detailed timeline for progression to full structural separation. Parties have raised issues as to potential anti-competitive issues arising from lack of full corporate separation and it is clear that the waiver authority in the ETP stipulation case and Section 4928.17, Revised Code, was designed as an interim arrangement. The breadth of this waiver request and the lack of any specificity as to the areas of non-compliance make it impossible for the Commission to find good cause for granting the extension of the general waiver. The Commission cannot grant a waiver where the applicant has been unable to state the actual company process, program or function that requires the waiver. If the Applicants find that their structure or code of conduct necessitates a waiver of certain Commission rules or regulations, they may apply in a separate proceeding.

K. <u>The Stipulation</u>

At the first day of hearing, FirstEnergy entered into a stipulation (RSP Stipulation) with IEU-Ohio; Cargill, Inc.; Ohio Hospital Association; Ohio Energy Group; and OPAE (Signatory Parties). Mr. Alexander testified in support of the RSP Stipulation, which is reflected in the RSP as revised. The Signatory Parties have agreed as part of the RSP Stipulation to support the RSP. Among other things, the RSP Stipulation increases the amounts that OE, CEI, and TE will make available for economic development activities from up to $5 million during the term of the RSP to up to $5 million annually during the term of the RSP. The RSP Stipulation also obligates the operating companies to meet with commercial and industrial customer groups at least annually, on request, to discuss service or reliability issues affecting those customers, and it provides for extending the term of a special contract, on request of the customer, through the period during which the extended RTC is in effect if doing so would "enhance or maintain jobs and economic conditions"... (FirstEnergy Ex 4). The Signatory Parties argue that the RSP Stipulation is consistent with the three objectives of the RSP set forth by the Commission and recommend that the RSP Stipulation be adopted by the Commission.

The OMA supports the provision of the RSP Stipulation that would permit extensions of special contracts for economic development. However, OMA notes that most of its members do not receive special contract service, but take service from commercial and industrial tariffs. It argues that the tariff rates are too high and that it cannot support a RSP that maintains these high rates. OMA urges for the establishment of a CBP.

OPAE asserts that the RSP Stipulation was entered into by knowledgeable parties who were part of the original ETP proceeding. OPAE contends that the RSP Stipulation represents a package that benefits ratepayers and the public interest.

OCC, GM and others submit that the RSP Stipulation, which recommends that the Commission approve the RSP as modified, violates the criteria for approving stipulations set out by the Commission and the Ohio Supreme Court and was entered into by only a limited number of parties. OCC and GM argue that, in the past, the Commission has used the following criteria in considering the reasonableness of a stipulation:

(1) Is the settlement a product of serious bargaining among capable, knowledgeable parties?

(2) Does the settlement, as a package, benefit ratepayers and the public interest?

(3) Does the settlement package violate any important regulatory principle or practice?

They note that the Ohio Supreme Court has endorsed the Commission's analysis using these criteria to resolve issues in a manner economical to ratepayers and public utilities. *Indus. Energy Consumers of Ohio Power Co. v. Pub. Util. Comm.*, 68 Ohio St.3d 559 (1994). It is argued that the RSP Stipulation does not benefit ratepayers, and violates important regulatory principles and, therefore, should be rejected. NOPEC argues that those customers under special contracts which may be extended pursuant to the RSP Stipulation should pay their full share of RTC and RSC during the extended term of the contracts. NOPEC argues that to do otherwise would be discriminatory to customers not under special contracts.

The Commission finds that inasmuch as the substantive terms of the RSP Stipulation have been included in the revised RSP, these terms can be considered in the same fashion as the rest of the provisions of the RSP. Certain of the terms of the RSP Stipulation have already been addressed above. The primary issue arising from the RSP Stipulation is the provision that allows certain customers to extend the terms of their special contracts until the extended RTC ends which could be as late as 2010. NOPEC questions whether these customers are paying their fair share of transition costs. We believe the answer is yes, when viewed in the context of Section 4928.34 (A) (6), Revised Code. This section, which deals with capping rates during the MDP, provides that "the rate cap applicable to a customer receiving electric service pursuant to an arrangement approved by the commission under Section 4905.31 of the Revised Code is, for the term of the arrangement, the total of all rates and charges in effect under the arrangement." We do not interpret this provision as allowing special contract customers to avoid the payment of transition costs no more than the capping of tariff rates for all other customers meant that they were not paying for transition costs. Whether a customer pays the capped tariff rates or a special contract rate, transition costs are recovered through those rates. Consequently, the fact that special contracts may be extended to the end of the extended regulatory transition cost recovery period does not change the premise that transition costs are recovered as part of the cost of providing service to special contract customers. We do not find that the approval of such a provision discriminates against customers served under tariff rates. Rather, the extension of such contracts promotes economic development in Ohio, and is reasonable to include in a RSP.

L. Miscellaneous Issues

1. State Action

The RSP provides that, for the duration of the Plan, FirstEnergy's compliance with the provisions of this Plan shall constitute state action (FirstEnergy Ex. 6, Section VII). FirstEnergy contends that it has asked for a state action finding to provide a defense against a claim of antitrust violations. It argues that the Commission's approval of a RSP constitutes state action because the Applicants' activities under the RSP will be conducted pursuant to a clear expressed state policy and will be actively supervised by the state. FirstEnergy argues that meeting these criteria fulfills the U.S. Supreme Court's test for finding state action set forth in *California Retail Liquor Ass'n v. Midcal Aluminum Inc.*, 445 U.S. 97 (1980). FirstEnergy asserts that the RSP was offered in response to a specific request of the Commission and, if approved, would be carefully supervised and controlled by the Commission. Therefore, it believes it is entitled to a finding from the Commission that the RSP constitutes state action.

NOAC, WPS/Cleveland, GM, and OMG urge the Commission not to make a finding that approval of a RSP constitutes state action. They argue that there is no legal reason why the Applicants should be shielded from antitrust laws. They contend that the proposed RSP provides a substantial amount of discretion to the Applicants to operate under the Plan and the Plan does not fulfill a clearly articulate state policy. It is also pointed out that the Commission specifically found in approving FirstEnergy's ETP that the Commission's actions did not constitute state action.

The Commission routinely finds in entries and orders that its actions do not constitute state action. We see no reason why we should change our policy in this case. As we stated in the FirstEnergy ETP order, "It is not our intent to insulate FirstEnergy from any provisions of state or federal law that prohibits the restraint of trade" (ETP Opinion and Order at 71). Accordingly, we will not find that approval of a RSP for FirstEnergy constitutes state action.

2. Case No. 02-1944-EL-CSS Partial Payment Priority

The revised RSP provides that the supplier payment priority arrangements agreed to in Case No. 02-1944-EL-CSS (02-1944) shall continue unchanged through December 31, 2008, or such earlier date as a result of the early termination of the Plan (FirstEnergy Ex. 6, Section VIII at paragraph 10). Mr. Alexander testified that this provision is to assure CRES suppliers that the partial payment posting priority established in 02-1944 will remain in effect during the term of the RSP (FirstEnergy Ex. 5 at 5).

GM argues that the language used in this paragraph could be interpreted to create a fixed termination date of the payment priority arrangement, contrary the stipulation entered into by FirstEnergy, GM, WPS, and Staff. The stipulation and the Commission's order approving the stipulation did not contain a pre-arranged termination date, but could allow for termination in the event of a material change in the assumptions underlying the stipulation. GM asserts that the payment arrangement should continue during the RSP and beyond, until and unless a material change occurs within the meaning of the stipulation's termination provision.

The Commission finds that the terms of the stipulation and our opinion and order of August 6, 2003 in 02-1944 will control as to the termination of the agreed upon payment priority. It is not the Commission's intent to change the terms of the stipulation through the RSP.

3. CRES Creditworthiness and Security

The RSP states that a CRES supplier shall be deemed to be "credit worthy," as that term is used in Section II Paragraph 2(b), provided that such supplier meets the security/credit terms and conditions set forth in the Applicants' respective tariffs, as modified from time to time by the Commission (FirstEnergy Ex. 6, Section VIII, paragraph 11). Mr. Alexander testified that this provision is to provide assurance to CRES suppliers that existing supplier security/credit terms and conditions will be maintained during the period the RSP remains in effect (FirstEnergy Ex. 5 at 5).

GM argues that this provision would allow FirstEnergy to modify it creditworthiness standard during the term of the RSP if the Commission would approve such a modification. GM contends that no changes should be made to the creditworthiness standard during the RSP.

The Commission finds that the provision for CRES security/credit standards set forth in Section VIII paragraph 11 of the RSP is reasonable. There may be valid reasons why modifications to the standards may be necessary. We note that any proposed modification would need Commission approval which provides opposing parties the opportunity to provide comments to the Commission prior to any approval. Therefore, this provision will remain part of the RSP.

IV. COMMISSION MODIFIED RSP'S COMPLIANCE WITH SB 3

The parties that oppose the implementation of the RSP proposed by FirstEnergy have raised various arguments regarding whether or not the RSP comports with the policies and requirements of SB 3. In summary, opponents argue that FirstEnergy's Application does not establish a MBSSO and CPB in compliance with Section 4928.14, Revised Code. Further, they argue that the RSP constitutes a rate increase without following the procedures in Sections 4909.18 and 4909.19, Revised Code; violates the rate cap provisions of Sections 4928.34(A)(6) and 4928.35(A), Revised Code; continues the GTC beyond 2005 in violation of Section 4928.38, Revised Code; creates new regulatory assets in violation of Section 4928.40(A), Revised Code; and violates the terms of FirstEnergy's existing ETP and the Commission's stated goals for a RSP.

A. Section 4928.14, Revised Code, Filing

With regard to Section 4928.14, Revised Code, SB 3 requires that, after the end of the MDP, an electric utility will provide a "market-based standard service offer of all competitive retail electric services necessary to maintain essential electric service to consumers," as well as "the option to purchase competitive retail electric service the price of which is determined through a competitive bidding process." Section 4928.14, Revised Code. The CBP may also be replaced with other means to accomplish generally the same option for customers. Section 4928.14(B), Revised Code.

NOAC, OCC, OMG, PSEG and others argue that the Applicants' RSP falls short of meeting the criteria of Section 4928.14, Revised Code, and the Commission's rules. They contend that the RSP is not market-based, nor a variable rate required by Appendix A of Rule 4901:1-35-03, O.A.C. They argue that the generation prices set through the RSP are not based upon a willing buyer and seller but based upon a price at which FirstEnergy is willing to sell energy. It is also argued that the bidding process is flawed and contrary to the Commission's rules which support the inclusion of small CRES providers in the bidding process.

Applicants assert that they have filed for approval of their RSP as a MBSSO and a CBP in accordance with the provisions of Section 4928.14, Revised Code. Mr. Alexander testified that the RSP provides for an average market-based generation price across all rate classes from 2006 through 2008 of approximately 4.6 cents/kWh. Further, Mr. Alexander believes that this price is consistent with market prices for similar services based on his general knowledge of the marketplace and is reasonable. He explained that the auctions in New Jersey produced an average price of 5.5 cents per kWh, which compares favorably to the 4.6 cents per kWh. (FirstEnergy Ex. 1 at 15-16; Tr. II at 7-8, 13-14) Moreover, FirstEnergy argues that its RSP price is within the range of projected wholesale and retail prices discussed by intervener witnesses in this case. For example, Cleveland/WPS witness Kevin C. Higgins stated that the wholesale on-peak market price for 2005 would be 3.85 cents per kWh (Cleveland/WPS Ex. 1 at 14), and Mr. Frye cited sources that project wholesale prices in 2006 through 2008 to be somewhere between 3.6 to 3.9 cents per kWh (NOAC/NOPEC Ex. 1 at 6), while Dominion witness Thomas J. Butler testified that Dominion Retail's projected retail price for generation, on average, would be 4.79 cents per kWh (Tr. VI at 177), and Reliant estimated the retail price to be as high as 6.14 cents per kWh (Affidavit of Mark Sudbey, filed Feb. 20, 2004). FirstEnergy's position is that clearly the 4.6 cents/kWh average retail price is a reasonable, market-based price.

FirstEnergy also states that its Plan provides for the use of a CBP to be implemented if generation prices through a CBP turn out to be lower than the RSP MBSSO. The Applicants also point out that the Commission has the flexibility to waive the CBP provided for under Section 4928.14(B), Revised Code, if there is an alternative means of giving customers a market-based rate.

The Commission finds that the procedure set forth in the RSP, as modified by the Commission, does provide consumers with market-based rates. Based upon the pricing information provided by various parties to this proceeding, we find that the Applicants' 4.6 cents/kWh price for generation during 2006 through 2008 is a reasonable reflection of what market prices may be during that period. Additionally, the Commission has substantially limited the cost adjustments for generation service to those relating to taxes and for distribution service to those set forth in the existing ETP settlement. More importantly, however, adequate safeguards are in place to allow the Commission to monitor the prices and confirm that, over time, those prices remain market-based and that consumers have adequate options for choosing among generation suppliers. Through this order, the Commission is directing that FirstEnergy undertake a CBP to ensure that customers receive the benefits of CBP rates should they be lower than rates established through a RSP. The RSP that we propose complies with the requirements of Section 4928.14, Revised Code. Section 4928.14, Revised Code, provides the Commission with flexibility in approving processes for determining market-based rates for the standard service offer. We find that, for FirstEnergy, the methodology for establishing a MBSSO set forth in this order is reasonable. We also find that, by establishing the MBSSO with price monitoring, the RSP provides a reasonable alternative to a more traditional CBP, provides for a reasonable means of customer participation, and fulfills the requirements of Section 4928.14 (B), Revised Code.

B. <u>Compliance with Section 4909.18, Revised Code, and SB 3 Rate Cap Provisions</u>

Section 4928.14(A), Revised Code, provides that the MBSSO shall be filed with the Commission under Section 4909.18, Revised Code: SB 3 also imposes a cap on unbundled rates and provides that rate schedules established for the MDP shall not be adjusted during that period, except as provided for in SB 3 (Sections 4928.34(A)(6) and 4928.35(A), Revised Code). NOAC, NOPEC, GM and others argue that the RSP proposed by FirstEnergy provides for rate increases without fulfilling the requirements set forth in Chapter 4909, Revised Code, and in violation of SB 3. NOAC argues that FirstEnergy's RSP proposes several immediate rate hikes and provides a mechanism for several future rate hikes. It argues that the Plan includes: 1) a mechanism for an increase in tariffed generation charges; 2) the addition of interest charges to the deferral of shopping credits incentives; 3) the imposition of a RSC; and 4) a mechanism for increases to distribution rates. Further, NOAC argues that proposed accrual of interest on shopping credit incentive deferrals violates the provisions of SB 3 cited above. It is argued that rate adjustments and deferrals, above those authorized in the ETP, either should be considered using the rate increase procedures of Chapter 4909 or not allowed as violations of the SB 3 rate cap provisions.

FirstEnergy asserts that the application for a RSP was filed as an ATA (application for tariff approval), not for an increase in rates, and that it was filed pursuant to Section 4928.14, Revised Code. FirstEnergy contends that with the approval of its RSP, there are no actual increases in any rates or charges. FirstEnergy points out that the deferrals that are established as part of the RSP only extend the recovery of the RTC, not increase the rate. Further, any changes in generation and distribution rates that could be requested by FirstEnergy would have to be shown to be just and reasonable and be approved by the Commission upon the filing of an application. With respect to the implementation of an RSC, FirstEnergy asserts that, given that the RSC is simply a component of the market-based rate proposed in the RSP, the RSC cannot be characterized as a new rate, much less an increased rate.

With the adoption of a RSP as modified by the Commission, we find that several of the concerns regarding rate increases and violation of the SB 3 rate cap provisions have been rendered moot. Regardless of the modifications made by the Commission, the establishment of the RSP does not require the filing of an application to increase rates pursuant to Chapter 4909, Revised Code. The establishment of a RSP as set forth in this order does not increase the generation charge, distribution charge, or the transition charges paid by customers. Any future adjustments to generation and distribution rates, as limited as they are, would be considered in separate applications filed by FirstEnergy and are not being approved as part of this application. The form and specific requirements of such applications can be considered if and when FirstEnergy seeks to adjust such rates in accordance with the ETP or the RSP being approved herein. Likewise, the establishment of a RSC after the MDP is not considered part of a noncompetitive service, which would be subject to the requirements of a Chapter 4909 rate increase application. Additionally, the modifications to the RTC and the establishment of an extended RTC to recover new deferrals all relate to competitive services and are not subject to a Chapter 4909 rate increase application. Further, we are not increasing any of the rate components established in the ETP during the MDP consistent with the rate cap provisions of Section 4928.34(A)(6) and 4928.35(A), Revised Code.

C. Compliance with Section 4928.38, Revised Code

Section 4928.38, Revised Code, states that the "utility's receipt of transition revenues shall terminate at the end of the market development period." NOAC and Reliant argue that the establishment of an RSC after the MDP, which is the same amount as the GTC in effect during the MDP, is in actuality a continuation of the GTC and, therefore, a violation of Section 4928.38, Revised Code. NOAC acknowledges that there are provisions within SB 3 which permit the continuation of the RTC beyond the MDP; however, no such provisions exist for continuing the GTC.

FirstEnergy argues that the establishment of a RSC does not violate Section 4928.38, Revised Code. FirstEnergy states that the RSC is part of the total price at which the Applicants will sell generation during the period 2006 through 2008. The RSC is intended to compensate the Applicants for, among other things, the cost of reserving affiliate generation to backstop Ohio POLR service and compensate FirstEnergy for maintaining the ability to provide generation to all of its shopping and non-shopping customers (Tr. I at 205; FirstEnergy Ex. 1 at 18). FirstEnergy asserts that the RSC does not perform the same function as the GTC, is not a continuation of the GTC, and has nothing to do with transition costs; therefore, there is no violation of Section 4928.38, Revised Code.

The Commission finds no merit to NOAC's and Reliant's contention that the establishment of the RSC violates Section 4928.38, Revised Code. As FirstEnergy has stated, and we find that the RSC serves a different function than the GTC. It is part of the price at which FirstEnergy has agreed to provide generation. It is not meant to recover generation transition costs. Consequently, we find that Section 4928.38, Revised Code, has no applicability to the RSC.

D. Compliance with Section 4928.40, Revised Code

Section 4928.40, Revised Code, addresses the recovery of generation and regulatory transition costs. It also authorizes the Commission to "conduct a periodic review no more often than annually and, as it determines necessary, adjust the transition charges of the electric utility...." Further, this section provides that the "Commission shall not permit the creation or amortization of additional regulatory assets without notice and an opportunity to be heard through an evidentiary hearing and shall not increase the charge recovering such revenue requirement associated with regulatory assets."

NOAC argues that the accrual of interest on shopping credit deferrals does not qualify as a "regulatory asset" as defined in Section 4928.01(A)(26), Revised Code, and, therefore, is not a regulatory asset that can be created under Section 4928.40(A), Revised Code. NOAC argues that interest is an item that can be added to a regulatory asset but it is not a regulatory asset by itself.

FirstEnergy argues that the statute defines "regulatory asset" as "the unamortized net regulatory assets that are capitalized or deferred on the regulatory books of the electric utility," pursuant to a Commission order or generally accepted accounting principles, "that would otherwise have been charged to expenses as incurred...." FirstEnergy states that, under its proposed RSP, the interest on shopping credit incentive deferrals and other regulatory assets are to be deferred on the Applicants' books and, therefore, meet the definition of regulatory assets.

The Commission has in the past authorized accounting deferrals and, based on the circumstances, has permitted the accrual of interest on deferrals. We find nothing in Sections 4928.01(A)(26) or 4928.40, Revised Code, which precludes the Commission from allowing a reasonable rate of interest on deferrals to be part of regulatory assets. To the extent that we permit interest on the amortization of regulatory assets, we have the authority to permit the recovery of the deferred interest through Section 4928.40(A), Revised Code.

E. Commission's RSP Goals

FirstEnergy offered a RSP in response to the Commission's September 23, 2003 entry in Case No. 03-1461-EL-UNC regarding the establishment of FirstEnergy's shopping credits for 2003. In that entry, the Commission requested that FirstEnergy develop a plan that balanced three objectives: (1) rate certainty, (2) financial stability for FirstEnergy, and (3) the further development of competitive markets. The Commission finds that the RSP, as modified by the Commission, fulfills all of these goals. Under the RSP, FirstEnergy will assume the risk of continuing to supply POLR services to its Ohio customers at a fixed, market-based generation price, using its generation assets after the end of the MDP, while still maintaining its financial integrity. The RSP provides for stable rates through 2008, subject to limited Commission-approved adjustments, while continuing to support shopping. The RSP, as revised, also provides FirstEnergy with the ability to maintain financial stability through the term of the Plan by adjusting kWh sales targets and extending the period for regulatory transition cost recovery to account for the lower-than-expected sales resulting from the sluggish economic conditions and the effect of the accrual of carrying charges.

Another important aspect of FirstEnergy's RSP is that it will provide customers the opportunity to shop against the price of generation established by the Plan and, if the market supports lower pricing, customers can shop. The RSP also permits the Commission to periodically evaluate the RSP prices against a competitive bidding process. If the market prices are lower, the Commission may terminate the RSP and accept the bids for generation service. As set forth above, a CBP process is to be conducted and the results submitted to the Commission for its consideration by December 1, 2004. We find that these provisions of the Plan will help further develop a competitive market. Accordingly, we find the RSP, as modified by the Commission, will meet all three of the objectives set out in our September 23, 2003 entry in Case No. 03-1461-EL-UNC. We also find that the requirements and characteristics of the FirstEnergy territory mandate a plan that is specific to that area and should not be considered precedent for other EDU plans.

V. FINDINGS OF FACT AND CONCLUSIONS OF LAW

(1) On October 21, 2003, FirstEnergy filed an application for authority to continue and modify certain regulatory accounting practices and procedures, for tariff approvals, and to establish regulatory transition charges following the MDP.

(2) The local public hearings were held as scheduled in Toledo, Cleveland, and Kent. The evidentiary hearing commenced on February 11, 2004, and continued through February 25, 2004. On February 25, 2004, FirstEnergy offered rebuttal testimony and a revised rate stabilization plan. Additional, testimony was heard on March 1, 2004.

(3) A partial Stipulation and Recommendation, resolving some issues in this case for certain signatory parties, was filed on February 11, 2004.

(4) FirstEnergy proposes in its application to either (1) establish a CBP to determine standard offer generation service rates commencing as of January 1, 2006 under which the prices for generation services would be determined by the current market prices, or (2) implement a comprehensive RSP designed to provide stable long-term competitive pricing of energy services

(5) The Commission supports the use of a CBP to continue to monitor the necessity of a RSP on a going forward basis. We believe that a CBP should be used to evaluate the reasonableness of the RSP and to assure the Commission and all interested stakeholders that the charges for generation service under the RSP do not exceed long-term market prices that result from a CBP. The Commission will cause the Applicants to undertake a CBP.

(6) The Commission, after considering the numerous arguments for and against the adoption of a RSP, finds that it is prudent to establish a RSP for FirstEnergy unless the CBP can provide better benefits for customers. We concur with our Staff that a well-functioning and competitive wholesale market is a necessary precondition for an efficient retail market and that such a market does not exist at present. Efforts by FERC to standardize the design of electric markets to address reliability and pricing concerns have met stiff opposition and may take considerable more time to put in place. Delays that have occurred in the establishment of RTOs and the development of competitive wholesale generation markets require that we develop a standard service offers that provides protections against the possibility of rate shock once the MDP ends, as well as promotes further development of a competitive generation market.

(7) A properly structured RSP can provide stable rates through 2008, fulfill requirements of Section 4928.14, Revised Code, and continue to foster the development of a competitive market.

(8) In consideration of the approved ETP for FirstEnergy, and the provision for an appropriate rate stabilization charge as part of the RSP, adjustments to generation charges during the RSP should be limited to cost increases related to material changes in tax regulations or laws.

(9) The RSP should not include the ability to increase distribution rates above those exceptions set forth in the stipulated ETP.

(10) Paragraph 7 of the RSP provides FirstEnergy the ability to adjust charges for retail transmission, net congestion, and ancillary services beginning in 2006. Interested parties to this proceeding will be directed to meet to determine the best approach for billing shopping customers for such services once the MDP has ended.

(11) The RSC represents the price for FirstEnergy to accept the risk inherent in a rate stabilization plan. The RSC cannot be considered a continued collection of the GTC.

(12) The Commission will permit FirstEnergy to modify the accounting of the 5% reduction and customer charge credits as reductions of the GTC and the RTC. However, for residential customers to receive the full benefit of the customer charge credits, the sales targets and time periods for the recovery of regulatory transition costs should not be lengthened or adjusted to account for the RTC rate reduction attributable to the customer charge credits.

(13) The ETP allowed for the end date for collection of the RTC to be adjusted for economic conditions. The Applicants' proposed adjustments to the RTC recovery periods should be allowed as delineated in the Revised Plan. The Applicants should meet with our Staff to recalculate new sales target levels for recovery of regulatory transition costs.

(14) The collection of interest on the shopping credit deferrals is an appropriate part of the overall RSP and is authorized by the ETP. The collection of interest should begin on January 1, 2004.

(15) The 2005 shopping credit values should be derived in accordance with the ETP stipulations.

(16) The 2005 shopping credit by class should be used as the avoided cost cap for the RSP. The 2005 shopping credit would

be more appropriate as the cap since it would further stabilize rates during the transition into the Plan.

(17) The shopping credit/avoidable expense model in the Plan furthers the Commission's stated goals of rate certainty, financial stability for the Applicant and promotion of the market.

(18) The issue of the POLR price for returning customers is crucial for marketers and aggregators to offer competitive products and for the appropriate risks to be imposed on those customers. We believe that the relevant market for analyzing and specifying market pricing is the EDU. To the extent practical, the Applicants should base pricing on a portfolio approach, using monthly forwards to purchase blocks of power. FirstEnergy should submit to the Commission, within 90 days of this order, a new pricing plan for returning customers that incorporates these concepts.

(19) The impact of the RSP on shopping cannot be determined at this time, and there is a definite benefit to the retention of at least minimum shopping levels as the market develops. The supply of MSG when the shopping levels would fall below 20% would ensure those minimum levels of shopping.

(20) Inasmuch as FirstEnergy has proposed reducing funding for energy efficiency programs for the period of 2006 through 2008 from $5 million to $1.25 million per year, we believe that the $10 million of additional funding FirstEnergy has agreed to provide should be divided equally between energy efficiency programs and economic development activities.

(21) The Revised Plan's termination provisions are reasonable as clarified in the record of this case. The criteria for termination would require 12 months prior written notice and the filing of an application with the Commission that establishes a clear nexus between the environmental action(s) and the FirstEnergy decision to retire or shut down the units.

(22) In consideration of the economic conditions that inhibited the retirement of the debt associated with the facilities, FirstEnergy has shown good cause to extend the financial separation waiver. The breadth of this waiver request and the lack of any specificity as to the areas of non-compliance make it impossible for the Commission to find good cause for granting the extension of the general corporate separation waiver.

(23) The primary issue arising from the RSP Stipulation is the provision that allows certain customers to extend the terms of their special contracts until the extended RTC ends which could be as late as 2010. The approval of such a provision does not discriminate against customers served under tariff rates. Rather, the extension of such contracts promotes economic development in Ohio, and is reasonable to include in a RSP.

(24) Approval of a RSP for FirstEnergy does not constitute state action.

(25) The terms of the stipulation and our opinion and order of August 6, 2003 in 02-1944 will control as to the termination of the agreed upon payment priority.

(26) The Commission finds that the provision for CRES security/credit standards set for in Section VIII paragraph 11 of the RSP is reasonable.

(27) The RSP, as modified, does not violate the requirements of Section 4928.14, Revised Code. By establishing the MBSSO with price monitoring, the RSP provides a reasonable alternative to a more traditional CBP, provides for a reasonable means of customer participation, and fulfills the requirements of Section 4928.14 (B), Revised Code.

(28) The modifications to the RTC and the establishment of an extended RTC to recover new deferrals all relate to noncompetitive services and are not subject to a Chapter 4909 rate increase application. Further, there are no increases to any of the rate components established in the ETP during the MDP to be in violation of the rate cap provisions of Section 4928.34(A)(6) and 4928.35(A), Revised Code.

(29) The establishment of the RSC does not violate Section 4928.38, Revised Code.

(30) The establishment and deferral of interest on the amortization of regulatory assets after the MDP ends does not violate Section 4928.40(A), Revised Code.

(31) The RSP, as modified by the Commission, balanced three objectives: (1) rate certainty, (2) financial stability for FirstEnergy, and (3) the further development of competitive markets.

ORDER:

It is, therefore,

ORDERED, That FirstEnergy undertake a CBP consistent with this order and schedule a meeting with our staff and other interested parties to this proceeding to establish further requirements of the CBP. It is, further,

ORDERED, That the FirstEnergy's RSP is approved, to the extent and subject to the modifications and conditions set forth above. It is, further,

ORDERED, That FirstEnergy file tariffs for Commission approval that reflect the terms of the RSP as modified by this order within 75 days. It is, further,

ORDERED, That interested parties to this proceeding shall meet to determine the best approach for billing shopping customers for retail transmission, net congestion, and ancillary services once the MDP has ended. It, is further,

ORDERED, That FirstEnergy meet with our staff to recalculate new sales target levels for recovery of regulatory transition costs consistent with this order. It is, further,

ORDERED, That FirstEnergy shall submit its methodology for the supply of MSG within 90 days of this order. It is, further,

ORDERED, That FirstEnergy shall submit a new pricing plan for the POLR price for returning customers within 90 days of this order. It is, further,

ORDERED, That FirstEnergy's request to adjust the 2005 shopping credits is denied. The 2005 shopping credits should be derived in accordance with the ETP stipulation. It is, further, ORDERED, That a copy of this opinion and order be served upon all parties of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber, Chairman

Ronda Hartman Fergus

Judith A. Jones
concurring opinion att.

Donald L. Mason

Clarence D. Rogers, Jr.

RRG/SDL:ct

Entered in the Journal
JUN 9 2004

Reneè J. Jenkins
Secretary

Appendix

List of Acronyms

SB 3	Amended Substitute Senate Bill No. 3 of the 123rd General Assembly
ETP	Electric Transition Plan
MDP	market development period
RTC	regulatory transition charges
OE	Ohio Edison Company
TE	Toledo Edison Company
CEI	Cleveland Electric Illuminating Company
RSP or Plan	Rate Stabilization Plan
OCC	Ohio Consumers' Counsel
GM	Green Mountain Energy Company
(Ohio Marketers Group or OMG)	MidAmerican Energy Company, Strategic Energy LLC, and Constellation NewEnergy, Inc.
WPS	WPS Energy Services
OPAE	Ohio Partners for Affordable Energy
IEU-Ohio	Industrial Energy Users-Ohio
CPS	Constellation Power Source, Inc.
OMA	Ohio Manufacturers' Association
NOAC	Northwest Ohio Aggregation Coalition on behalf of City of Toledo, Lucas County, City of Maumee, City of Northwood, City of Northwood, City of Oregon, City of Perrysburg, City of Sylvania, and Village of Holland
NOPEC	The Northeast Ohio Public Energy Council
PSEG	PSEG Energy Resources and Trade
CBP	Competitive bidding process
POLR	Provider of last resort
MBSSO	Market-Based Standard Service Offer
CRES	Competitive retail electric service
FERC	Federal Energy Regulatory Commission
RTO	Regional Transmission Organization
RSC	Rate Stabilization Charge
GTC	Generation transition charge
MISO	Midwest ISO
PJM	PJM Interconnect LLC
AEP	American Electric Power
EDU	Electric distribution utilities
MSG	Market Support Generation
FES	FirstEnergy Solutions

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Applications of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Continue and Modify Certain Regulatory Accounting Practices and Procedures, for Tariff Approvals and to Establish Rates and Other Charges Including Regulatory Transition Charges Following the Market Development Period.	)	Case No. 03-2144-EL-ATA

OPINION OF COMMISSIONER CLARENCE D. ROGERS, JR., DISSENTING IN PART AND CONCURRING IN PART

The 1999 Senate Bill 3 restructured the electric industry in Ohio. It mandated the end of the old program of granting franchised monopolies the right to sell power based on cost of service and in its stead instituted the concept of market based rates. Electric companies were required to institute transition plans that included the collection of transition costs with market development periods to end no later than the end of 2005. This Commission was to oversee and approve: 1) a nondiscriminatory, market-based standard offer; 2) a competitive bid option for retail consumers; and 3) the divestiture of all generation facilities from the regulated distribution utility to an independent supplier or a nonjurisdictional affiliate.

The Rate Stabilization Plan for the FirstEnergy operating companies, CEI, Ohio Edison and Toledo Edison, as approved by the Public Utilities Commission today, with certain recommended modifications, is a departure from the concept envisioned by the legislature and this Commission. The modified Plan, if accepted by FirstEnergy, would set the course for electric service rates and competition in Northern Ohio until the end of 2008.

Although I agree with many of the changes to the Plan as directed by the Commission in the Order, I cannot sign the Opinion and Order as it maintains and, in fact, ensures that customers in the FirstEnergy territory will pay the highest rates in Ohio. Therefore, the plan does not best serve the public. And although not the fault of the Commission, the approved plan does not live up to the legislative promise to consumers. There was an expectation that by paying off First Energy's stranded costs, electric rates would be dramatically lowered by the end of the market development period.

It is clear that the market has not matured sufficiently for the legislative-directed competitive bid to serve as the standard service offer. Recognizing this, the PUCO encouraged the FirstEnergy companies to file a rate stabilization plan that balanced three objectives: 1) rate certainty, 2) financial stability for the FirstEnergy operating companies, and 3) development of the competitive market. The problem is that the Plan stabilizes rates at too high a cost; does not adequately promote competition; but does provide financial stability for FirstEnergy.

One cannot ignore the fact that the Commission had to "encourage" FirstEnergy to file the Rate Stabilization Plan, as opposed to ordering it. This has placed FirstEnergy in a powerful bargaining position. At the recent oral arguments, the company reminded the Commission that it had the ability to withdraw the application at any time and not accept any amendments or offer any re-openers. FirstEnergy has placed itself in a strong position, and has basically said "take it or leave it".

If First Energy carries out that threat, the Commission, and ultimately consumers, would be left with a standard service offer based on a competitive bid in a market that most experts agree has not developed in a manner anticipated by the deregulation legislation. Although the Order provides that the competitive bid be tested against the rate offered in the Rate Stabilization Plan, we can not be sure that such a market bid will produce a better deal for consumers.

The bottom line is the Plan neither offers a fair rate for consumers nor does it further the development of competition. The Rate Stabilization Charge, which is the insurance premium charge to be collected by FirstEnergy for offering a Rate Stabilization Plan, was set by FirstEnergy at the same rate as the generation transition charge, which is better known as the stranded cost recovery charge. FirstEnergy has offered no evidence, studies or analysis to support this charge other than the judgment of the Chairman of FirstEnergy companies. I have gone on record in another industry to voice my objection to signing an Order that requires the payment of this kind of charge without any additional justification. I must do the same here.

Finally, I am concerned that the structure of the Plan may impede the growth of competition in this region. The governmental aggregation groups in Ohio are the nationally acclaimed success stories of deregulation. Under the Plan they do not benefit. Although the Rate Stabilization Plan as modified in the Opinion and Order does more to benefit the consumers than the original stipulation, the overall impact of FirstEnergy's Plan will not be advantageous to the economic and social well-being of the northern part of the Ohio.

Clarence D. Rogers, Jr., Commissioner

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Applications of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Continue and Modify Certain Regulatory Accounting Practices and Procedures, for Tariff Approvals and to Establish Rates and Other Charges Including Regulatory Transition Charges Following the Market Development Period.	)	Case No. 03-2144-EL-ATA

CONCURRING OPINION OF COMMISSIONER JUDITH A. JONES

I concur with the Commission's approval of the revised application, as modified, submitted by FirstEnergy for authority to continue and modify certain regulatory accounting practices and procedures, for tariff approvals and to establish regulatory transition charges following the market development period. FirstEnergy proposed to either (1) establish a competitive bidding process (CBP) to determine standard offer generation service rates commencing as of January 1, 2006 whereby generations prices for generation services would be determined by the current market prices, or (2) implement a comprehensive Rate Stabilization Plan (RSP) designed to provide stable long-term competitive pricing of energy services for customers.

The Commission had requested that First Energy develop a plan that achieved three objectives: (1) rate certainty and stability for consumers, (2) financial stability for FirstEnergy, and (3) development of competitive markets.

I believe the key to the Order is the Commission finding that a Competitive Bid Process (CBP) should be conducted by First Energy to evaluate whether customers are better served by the establishment of a RSP or a CBP. If the CBP prices are lower that those of the RSP, then there may not be a need for the RSP. A CBP can be used to assure the Commission and all interested stakeholders that the charges for generation service under the RSP do not exceed long-term market prices that result from a CBP.

If needed, the RSP as modified will fulfill the Commission's objectives. Although I was discouraged that FirstEnergy set the provider of last resort (POLR) risk premium, the Rate Stabilization Charge, at such a high level without cost-based justification. First Energy will continue to supply POLR services to its Ohio consumers at a fixed, market-based generation price. The RSP provides for stable rates through 2008 while continuing to support shopping. The RSP, as revised, also provides First Energy with the ability to maintain financial stability through the term of the Plan. Further, the RSP will provide customers the opportunity to shop against the price of generation established by the plan and, if the market supports lower pricing, customers can shop. The Commission will be periodically measuring the RSP prices against a competitive bidding process. If the market prices are lower, the Commission may terminate the RSP and accept bids for generation.

I agree with the Commission's concern that the impact of the RSP on shopping cannot be determined at this time, and there is a definite benefit to the retention of at least minimum shopping levels as the market develops. The supply of Market Support Generation (MSG) when the shopping levels would fall below 20 percent would ensure those minimum levels of shopping.

Judith A. Jones

Judith A. Jones, Commissioner

4903.09 Written opinions filed by commission in all contested cases.

In all contested cases heard by the public utilities commission, a complete record of all of the proceedings shall be made, including a transcript of all testimony and of all exhibits, and the commission shall file, with the records of such cases, findings of fact and written opinions setting forth the reasons prompting the decisions arrived at, based upon said findings of fact.

4903.16 Stay of execution.

A proceeding to reverse, vacate, or modify a final order rendered by the public utilities commission does not stay execution of such order unless the supreme court or a judge thereof in vacation, on application and three days' notice to the commission, allows such stay, in which event the appellant shall execute an undertaking, payable to the state in such a sum as the supreme court prescribes, with surety to the satisfaction of the clerk of the supreme court, conditioned for the prompt payment by the appellant of all damages caused by the delay in the enforcement of the order complained of, and for the repayment of all moneys paid by any person, firm, or corporation for transportation, transmission, produce, commodity, or service in excess of the charges fixed by the order complained of, in the event such order is sustained.

4905.09 Substantial compliance.

A substantial compliance by the public utilities commission with the requirements of Chapters 4901., 4903., 4905., 4907., 4909., 4921., 4923., and 4925. of the Revised Code is sufficient to give effect to all its rules, orders, acts, and regulations. Such rules, orders, acts, and regulations shall not be declared inoperative, illegal, or void for an omission of a technical nature in respect to such requirements. Such chapters do not affect, modify, or repeal any law fixing the rate which a company operating a railroad may demand and receive for the transportation of passengers.

4909.15 Fixation of reasonable rate.

(A) The public utilities commission, when fixing and determining just and reasonable rates, fares, tolls, rentals, and charges, shall determine:

(1) The valuation as of the date certain of the property of the public utility used and useful in rendering the public utility service for which rates are to be fixed and determined. The valuation so determined shall be the total value as set forth in division (J) of section 4909.05 of the Revised Code, and a reasonable allowance for materials and supplies and cash working capital, as determined by the commission.

The commission, in its discretion, may include in the valuation a reasonable allowance for construction work in progress but, in no event, may such an allowance be made by the commission until it has determined that the particular construction project is at least seventy-five per cent complete.

In determining the percentage completion of a particular construction project, the commission shall consider, among other relevant criteria, the per cent of time elapsed in construction; the per cent of construction funds, excluding allowance for funds used during construction, expended, or obligated to such construction funds budgeted where all such funds are adjusted to reflect current purchasing power; and any physical inspection performed by or on behalf of any party, including the commission's staff.

A reasonable allowance for construction work in progress shall not exceed ten per cent of the total valuation as stated in this division, not including such allowance for construction work in progress.

Where the commission permits an allowance for construction work in progress, the dollar value of the project or portion thereof included in the valuation as construction work in progress shall not be included in the valuation as plant in service until such time as the total revenue effect of the construction work in progress allowance is offset by the total revenue effect of the plant in service exclusion. Carrying charges calculated in a manner similar to allowance for funds used during construction shall accrue on that portion of the project in service but not reflected in rates as plant in service, and such accrued carrying charges shall be included in the valuation of the property at the conclusion of the offset period for purposes of division (J) of section 4909.05 of the Revised Code.

From and after April 10, 1985, no allowance for construction work in progress as it relates to a particular construction project shall be reflected in rates for a period exceeding forty-eight consecutive months commencing on the date the initial rates reflecting such allowance become effective, except as otherwise provided in this division.

The applicable maximum period in rates for an allowance for construction work in progress as it relates to a particular construction project shall be tolled if, and to the extent, a delay in the in-service date of the project is caused by the action or inaction of any federal, state, county, or municipal agency having jurisdiction, where such action or inaction relates to a change in a rule, standard, or approval of such agency, and where such action or inaction is not the result of the failure of the utility to reasonably endeavor to comply with any rule, standard, or approval prior to such change.

In the event that such period expires before the project goes into service, the commission shall exclude, from the date of expiration, the allowance for the project as construction work in progress from rates, except that the commission may extend the expiration date up to twelve months for good cause shown.

In the event that a utility has permanently canceled, abandoned, or terminated construction of a project for which it was previously permitted a construction work in progress allowance, the commission immediately shall exclude the allowance for the project from the valuation.

In the event that a construction work in progress project previously included in the valuation is removed from the valuation pursuant to this division, any revenues collected by the utility from its customers after April 10, 1985, that resulted from such prior inclusion shall be offset against future revenues over the same period of time as the project was included in the valuation as construction work in progress. The total revenue effect of such offset shall not exceed the total revenues previously collected.

In no event shall the total revenue effect of any offset or offsets provided under division (A)(1) of this section exceed the total revenue effect of any construction work in progress allowance.

(2) A fair and reasonable rate of return to the utility on the valuation as determined in division (A)(1) of this section;

(3) The dollar annual return to which the utility is entitled by applying the fair and reasonable rate of return as determined under division (A)(2) of this section to the valuation of the utility determined under division (A)(1) of this section;

(4) The cost to the utility of rendering the public utility service for the test period less the total of any interest on cash or credit refunds paid, pursuant to section 4909.42 of the Revised Code, by the utility during the test period.

(a) Federal, state, and local taxes imposed on or measured by net income may, in the discretion of the commission, be computed by the normalization method of accounting, provided the utility maintains accounting reserves that reflect differences between taxes actually payable and taxes on a normalized basis, provided that no determination as to the treatment in the rate-making process of such taxes shall be made that will result in loss of any tax depreciation or other tax benefit to which the utility would otherwise be entitled, and further provided that such tax benefit as redounds to the utility as a result of such a computation may not be retained by the company, used to fund any dividend or distribution, or utilized for any purpose other than the defrayal of the operating expenses of the utility and the defrayal of the expenses of the utility in connection with construction work.

(b) The amount of any tax credits granted to an electric light company under section 5727.391 of the Revised Code for Ohio coal burned prior to January 1, 2000, shall not be retained by the company, used to fund any dividend or distribution, or utilized for any purposes other than the defrayal of the allowable operating expenses of the company and the defrayal of the allowable expenses of the company in connection with the installation, acquisition, construction, or use of a compliance facility. The amount of the tax credits granted to an electric light company under that section for Ohio coal burned prior to January 1, 2000, shall be returned to its customers within three years after initially claiming the credit through an offset to the company's rates or fuel component, as determined by the commission, as set forth in schedules filed by the company under section 4905.30 of the Revised Code. As used in division (A)(4)(c) of this section, "compliance facility" has the same meaning as in section 5727.391 of the Revised Code.

(B) The commission shall compute the gross annual revenues to which the utility is entitled by adding the dollar amount of return under division (A)(3) of this section to the cost of rendering the public utility service for the test period under division (A)(4) of this section.

(C) The test period, unless otherwise ordered by the commission, shall be the twelve-month period beginning six months prior to the date the application is filed and ending six months subsequent to that date. In no event shall the test period end more than nine months subsequent to the date the application is filed. The revenues and expenses of the utility shall be determined during the test period. The date certain shall be not later than the date of filing.

(D) When the commission is of the opinion, after hearing and after making the determinations under divisions (A) and (B) of this section, that any rate, fare, charge, toll, rental, schedule, classification, or service, or any joint rate, fare, charge, toll, rental, schedule, classification, or service rendered, charged, demanded, exacted, or proposed to be rendered, charged, demanded, or exacted, is, or will be, unjust, unreasonable, unjustly discriminatory, unjustly preferential, or in violation of law, that the service is, or will be, inadequate, or that the maximum rates, charges, tolls, or rentals chargeable by any such public utility are insufficient to yield reasonable compensation for the service rendered, and are unjust and unreasonable, the commission shall:

(1) With due regard among other things to the value of all property of the public utility actually used and useful for the convenience of the public as determined under division (A)(1) of this section, excluding from such value the value of any franchise or right to own, operate, or enjoy the same in excess of the amount, exclusive of any tax or annual charge, actually paid to any political subdivision of the state or county, as the consideration for the grant of such franchise or right, and excluding any value added to such property by reason of a monopoly or merger, with due regard in determining the dollar annual return under division (A)(3) of this section to the necessity of making reservation out of the income for surplus, depreciation, and contingencies, and;

(2) With due regard to all such other matters as are proper, according to the facts in each case,

(a) Including a fair and reasonable rate of return determined by the commission with reference to a cost of debt equal to the actual embedded cost of debt of such public utility,

(b) But not including the portion of any periodic rental or use payments representing that cost of property that is included in the valuation report under divisions (F) and (G) of section 4909.05 of the Revised Code, fix and determine the just and reasonable rate, fare, charge, toll, rental, or service to be rendered, charged, demanded, exacted, or collected for the performance or rendition of the service that will provide the public utility the allowable gross annual revenues under division (B) of this section, and order such just and reasonable rate, fare, charge, toll, rental, or service to be substituted for the existing one. After such determination and order no change in the rate, fare, toll, charge, rental, schedule, classification, or service shall be made, rendered, charged, demanded, exacted, or changed by such public utility without the order of the commission, and any other rate, fare, toll, charge, rental, classification, or service is prohibited.

(E) Upon application of any person or any public utility, and after notice to the parties in interest and opportunity to be heard as provided in Chapters 4901., 4903., 4905., 4907., 4909., 4921., and 4923. of the Revised Code for other hearings, has been given, the commission may rescind, alter, or amend an order fixing any rate, fare, toll, charge, rental, classification, or service, or any other order made by the commission. Certified copies of such orders shall be served and take effect as provided for original orders.

4928.01 Competitive retail electric service definitions.

(A) As used in this chapter:

(1) "Ancillary service" means any function necessary to the provision of electric transmission or distribution service to a retail customer and includes, but is not limited to, scheduling, system control, and dispatch services; reactive supply from generation resources and voltage control service; reactive supply from transmission resources service; regulation service; frequency response service; energy imbalance service; operating reserve-spinning reserve service; operating reserve-supplemental reserve service; load following; back-up supply service; real-power loss replacement service; dynamic scheduling; system black start capability; and network stability service.

(2) "Billing and collection agent" means a fully independent agent, not affiliated with or otherwise controlled by an electric utility, electric services company, electric cooperative, or governmental aggregator subject to certification under section 4928.08 of the Revised Code, to the extent that the agent is under contract with such utility, company, cooperative, or aggregator solely to provide billing and collection for retail electric service on behalf of the utility company, cooperative, or aggregator.

(3) "Certified territory" means the certified territory established for an electric supplier under sections 4933.81 to 4933.90 of the Revised Code as amended by Sub. S.B. No. 3 of the 123rd general assembly.

(4) "Competitive retail electric service" means a component of retail electric service that is competitive as provided under division (B) of this section.

(5) "Electric cooperative" means a not-for-profit electric light company that both is or has been financed in whole or in part under the "Rural Electrification Act of 1936," 49 Stat. 1363, 7 U.S.C. 901, and owns or operates facilities in this state to generate, transmit, or distribute electricity, or a not-for-profit successor of such company.

(6) "Electric distribution utility" means an electric utility that supplies at least retail electric distribution service.

(7) "Electric light company" has the same meaning as in section 4905.03 of the Revised Code and includes an electric services company, but excludes any self-generator to the extent it consumes electricity it so produces or to the extent it sells for resale electricity it so produces.

(8) "Electric load center" has the same meaning as in section 4933.81 of the Revised Code.

(9) "Electric services company" means an electric light company that is engaged on a for-profit or not-for-profit basis in the business of supplying or arranging for the supply of only a competitive retail electric service in this state. "Electric services company" includes a power marketer, power broker, aggregator, or independent power producer but excludes an electric cooperative, municipal electric utility, governmental aggregator, or billing and collection agent.

(10) "Electric supplier" has the same meaning as in section 4933.81 of the Revised Code.

(11) "Electric utility" means an electric light company that is engaged on a for-profit basis in the business of supplying a noncompetitive retail electric service in this state or in the businesses of supplying both a noncompetitive and a competitive retail electric service in this state. "Electric utility" excludes a municipal electric utility or a billing and collection agent.

(12) "Firm electric service" means electric service other than nonfirm electric service.

(13) "Governmental aggregator" means a legislative authority of a municipal corporation, a board of township trustees, or a board of county commissioners acting as an aggregator for the provision of a competitive retail electric service under authority conferred under section 4928.20 of the Revised Code.

(14) A person acts "knowingly," regardless of the person's purpose, when the person is aware that the person's conduct will probably cause a certain result or will probably be of a certain nature. A person has knowledge of circumstances when the person is aware that such circumstances probably exist.

(15) "Level of funding for low-income customer energy efficiency programs provided through electric utility rates" means the level of funds specifically included in an electric utility's rates on the effective date of this section pursuant to an order of the public utilities commission issued under Chapter 4905. or 4909. of the Revised Code and in effect on the day before the effective date of this section, for the purpose of improving the energy efficiency of housing for the utility's low-income customers. The term excludes the level of any such funds committed to a specific nonprofit organization or organizations pursuant to a stipulation or contract.

(16) "Low-income customer assistance programs" means the percentage of income payment plan program as prescribed in rules 4901:1-18-02(B) to (G) and 4901:1-18-04(B) of the Ohio Administrative Code in effect on the effective date of this section or, if modified pursuant to authority under section 4928.53 of the Revised Code, the program as modified; the home energy assistance program as prescribed in section 5117.21 of the Revised Code and in executive order 97-1023-V or, if modified pursuant to authority under section 4928.53 of the Revised Code, the program as modified; the home weatherization assistance program as prescribed in division (A)(6) of section 122.011 and in section 122.02 of the Revised Code or, if modified pursuant to authority under section 4928.53 of the Revised Code, the program as modified; the Ohio energy credit program as prescribed in sections 5117.01 to 5117.05, 5117.07 to 5117.12, and

5117.99 of the Revised Code or, if modified pursuant to authority under section 4928.53 of the Revised Code, the program as modified; and the targeted energy efficiency and weatherization program established under section 4928.55 of the Revised Code.

(17) "Market development period" for an electric utility means the period of time beginning on the starting date of competitive retail electric service and ending on the applicable date for that utility as specified in section 4928.40 of the Revised Code, irrespective of whether the utility applies to receive transition revenues under this chapter.

(18) "Market power" means the ability to impose on customers a sustained price for a product or service above the price that would prevail in a competitive market.

(19) "Mercantile commercial customer" means a commercial or industrial customer if the electricity consumed is for nonresidential use and the customer consumes more than seven hundred thousand kilowatt hours per year or is part of a national account involving multiple facilities in one or more states.

(20) "Municipal electric utility" means a municipal corporation that owns or operates facilities to generate, transmit, or distribute electricity.

(21) "Noncompetitive retail electric service" means a component of retail electric service that is noncompetitive as provided under division (B) of this section.

(22) "Nonfirm electric service" means electric service provided pursuant to a schedule filed under section 4905.30 of the Revised Code or pursuant to an arrangement under section 4905.31 of the Revised Code, which schedule or arrangement includes conditions that may require the customer to curtail or interrupt electric usage during nonemergency circumstances upon notification by an electric utility.

(23) "Percentage of income payment plan arrears" means funds eligible for collection through the percentage of income payment plan rider, but uncollected as of July 1, 2000.

(24) "Person" has the same meaning as in section 1.59 of the Revised Code.

(25) "Project" means any real or personal property connected with all or part of an industrial, distribution, commercial, or research facility, not-for-profit facility, or residence that is to be acquired, constructed, reconstructed, enlarged, improved, furnished, or equipped, or any combination of those activities, with aid furnished pursuant to sections 4928.61 to 4928.63 of the Revised Code for the purposes of not-for-profit, industrial, commercial, distribution, residential, and research development in this state. "Project" includes, but is not limited to, any small-scale renewables project.

(26) "Regulatory assets" means the unamortized net regulatory assets that are capitalized or deferred on the regulatory books of the electric utility, pursuant to an order or practice of the public utilities commission or pursuant to generally accepted accounting principles as a result of a prior commission rate-making decision, and that would otherwise have been charged to

expense as incurred or would not have been capitalized or otherwise deferred for future regulatory consideration absent commission action. "Regulatory assets" includes, but is not limited to, all deferred demand-side management costs; all deferred percentage of income payment plan arrears; post-in-service capitalized charges and assets recognized in connection with statement of financial accounting standards no. 109 (receivables from customers for income taxes); future nuclear decommissioning costs and fuel disposal costs as those costs have been determined by the commission in the electric utility's most recent rate or accounting application proceeding addressing such costs; the underpreciated costs of safety and radiation control equipment on nuclear generating plants owned or leased by an electric utility; and fuel costs currently deferred pursuant to the terms of one or more settlement agreements approved by the commission.

(27) "Retail electric service" means any service involved in supplying or arranging for the supply of electricity to ultimate consumers in this state, from the point of generation to the point of consumption. For the purposes of this chapter, retail electric service includes one or more of the following "service components": generation service, aggregation service, power marketing service, power brokerage service, transmission service, distribution service, ancillary service, metering service, and billing and collection service.

(28) "Small electric generation facility" means an electric generation plant and associated facilities designed for, or capable of, operation at a capacity of less than two megawatts.

(29) "Starting date of competitive retail electric service" means January 1, 2001, except as provided in division (C) of this section.

(30) "Customer-generator" means a user of a net metering system.

(31) "Net metering" means measuring the difference in an applicable billing period between the electricity supplied by an electric service provider and the electricity generated by a customer-generator which is fed back to the electric service provider.

(32) "Net metering system" means a facility for the production of electrical energy that does all of the following:

(a) Uses as its fuel either solar, wind, biomass, landfill gas, or hydropower, or uses a microturbine or a fuel cell;

(b) Is located on a customer-generator's premises;

(c) Operates in parallel with the electric utility's transmission and distribution facilities;

(d) Is intended primarily to offset part or all of the customer-generator's requirements for electricity.

(33) "Self-generator" means an entity in this state that owns an electric generation facility that produces electricity primarily for the owner's consumption and that may provide any such

excess electricity to retail electric service providers, whether the facility is installed or operated by the owner or by an agent under a contract.

(B) For the purposes of this chapter, a retail electric service component shall be deemed a competitive retail electric service if the service component is competitive pursuant to a declaration by a provision of the Revised Code or pursuant to an order of the public utilities commission authorized under division (A) of section 4928.04 of the Revised Code. Otherwise, the service component shall be deemed a noncompetitive retail electric service.

(C) Prior to January 1, 2001, and after application by an electric utility, notice, and an opportunity to be heard, the public utilities commission may issue an order delaying the January 1, 2001, starting date of competitive retail electric service for the electric utility for a specified number of days not to exceed six months, but only for extreme technical conditions precluding the start of competitive retail electric service on January 1, 2001.

4928.02 State policy.

It is the policy of this state to do the following throughout this state beginning on the starting date of competitive retail electric service:

(A) Ensure the availability to consumers of adequate, reliable, safe, efficient, nondiscriminatory, and reasonably priced retail electric service;

(B) Ensure the availability of unbundled and comparable retail electric service that provides consumers with the supplier, price, terms, conditions, and quality options they elect to meet their respective needs;

(C) Ensure diversity of electricity supplies and suppliers, by giving consumers effective choices over the selection of those supplies and suppliers and by encouraging the development of distributed and small generation facilities;

(D) Encourage innovation and market access for cost-effective supply- and demand-side retail electric service;

(E) Encourage cost-effective and efficient access to information regarding the operation of the transmission and distribution systems of electric utilities in order to promote effective customer choice of retail electric service;

(F) Recognize the continuing emergence of competitive electricity markets through the development and implementation of flexible regulatory treatment;

(G) Ensure effective competition in the provision of retail electric service by avoiding anticompetitive subsidies flowing from a noncompetitive retail electric service to a competitive retail electric service or to a product or service other than retail electric service, and vice versa;

(H) Ensure retail electric service consumers protection against unreasonable sales practices, market deficiencies, and market power;

(I) Facilitate the state's effectiveness in the global economy.

4928.03 Identification of competitive services and noncompetitive services.

Beginning on the starting date of competitive retail electric service, retail electric generation, aggregation, power marketing, and power brokerage services supplied to consumers within the certified territory of an electric utility are competitive retail electric services that the consumers may obtain subject to this chapter from any supplier or suppliers. In accordance with a filing under division (F) of section 4933.81 of the Revised Code, retail electric generation, aggregation, power marketing, or power brokerage services supplied to consumers within the certified territory of an electric cooperative that has made the filing are competitive retail electric services that the consumers may obtain subject to this chapter from any supplier or suppliers.

Beginning on the starting date of competitive retail electric service and notwithstanding any other provision of law, each consumer in this state and the suppliers to a consumer shall have comparable and nondiscriminatory access to noncompetitive retail electric services of an electric utility in this state within its certified territory for the purpose of satisfying the consumer's electricity requirements in keeping with the policy specified in section 4928.02 of the Revised Code.

4928.04 Additional competitive services.

(A) The public utilities commission by order may declare that retail ancillary, metering, or billing and collection service supplied to consumers within the certified territory of an electric utility on or after the starting date of competitive retail electric service is a competitive retail electric service that the consumers may obtain from any supplier or suppliers subject to this chapter. The commission may issue such order, after investigation and public hearing, only if it first determines either of the following:

(1) There will be effective competition with respect to the service.

(2) The customers of the service have reasonably available alternatives.

The commission shall initiate a proceeding on or before March 31, 2003, on the question of the desirability, feasibility, and timing of any such competition.

(B) In carrying out division (A) of this section, the commission may prescribe different classifications, procedures, terms, or conditions for different electric utilities and for the retail electric services they provide that are declared competitive pursuant to that division, provided the classifications, procedures, terms, or conditions are reasonable and do not confer any undue economic, competitive, or market advantage or preference upon any electric utility.

4928.05 Extent of exemptions.

(A)(1) On and after the starting date of competitive retail electric service, a competitive retail electric service supplied by an electric utility or electric services company shall not be subject to supervision and regulation by a municipal corporation under Chapter 743. of the Revised Code or by the public utilities commission under Chapters 4901. to 4909., 4933., 4935., and 4963. of the Revised Code, except section 4905.10, division (B) of 4905.33, and sections 4905.35 and 4933.81 to 4933.90; except sections 4905.06, 4935.03, 4963.40, and 4963.41 of the Revised Code only to the extent related to service reliability and public safety; and except as otherwise provided in this chapter. The commission's authority to enforce those excepted provisions with respect to a competitive retail electric service shall be such authority as is provided for their enforcement under Chapters 4901. to 4909., 4933., 4935., and 4963. of the Revised Code and this chapter.

On and after the starting date of competitive retail electric service, a competitive retail electric service supplied by an electric cooperative shall not be subject to supervision and regulation by the commission under Chapters 4901. to 4909., 4933., 4935., and 4963. of the Revised Code, except as otherwise expressly provided in sections 4928.01 to 4928.10 and 4928.16 of the Revised Code.

(2) On and after the starting date of competitive retail electric service, a noncompetitive retail electric service supplied by an electric utility shall be subject to supervision and regulation by the commission under Chapters 4901. to 4909., 4933., 4935., and 4963. of the Revised Code and this chapter, to the extent that authority is not preempted by federal law. The commission's authority to enforce those provisions with respect to a noncompetitive retail electric service shall be the authority provided under those chapters and this chapter, to the extent the authority is not preempted by federal law.

The commission shall exercise its jurisdiction with respect to the delivery of electricity by an electric utility in this state on or after the starting date of competitive retail electric service so as to ensure that no aspect of the delivery of electricity by the utility to consumers in this state that consists of a noncompetitive retail electric service is unregulated.

On and after that starting date, a noncompetitive retail electric service supplied by an electric cooperative shall not be subject to supervision and regulation by the commission under Chapters 4901. to 4909., 4933., 4935., and 4963. of the Revised Code, except sections 4933.81 to 4933.90 and 4935.03 of the Revised Code. The commission's authority to enforce those excepted sections with respect to a noncompetitive retail electric service of an electric cooperative shall be such authority as is provided for their enforcement under Chapters 4933. and 4935. of the Revised Code.

(B) Nothing in this chapter affects the authority of the commission under Title XLIX [49] of the Revised Code to regulate an electric light company in this state or an electric service supplied in this state prior to the starting date of competitive retail electric service.

4928.14 Market-based standard service offer.

(A) After its market development period, an electric distribution utility in this state shall provide consumers, on a comparable and nondiscriminatory basis within its certified territory, a market-based standard service offer of all competitive retail electric services necessary to maintain essential electric service to consumers, including a firm supply of electric generation service. Such offer shall be filed with the public utilities commission under section 4909.18 of the Revised Code.

(B) After that market development period, each electric distribution utility also shall offer customers within its certified territory an option to purchase competitive retail electric service the price of which is determined through a competitive bidding process. Prior to January 1, 2004, the commission shall adopt rules concerning the conduct of the competitive bidding process, including the information requirements necessary for customers to choose this option and the requirements to evaluate qualified bidders. The commission may require that the competitive bidding process be reviewed by an independent third party. No generation supplier shall be prohibited from participating in the bidding process, provided that any winning bidder shall be considered a certified supplier for purposes of obligations to customers. At the election of the electric distribution utility, and approval of the commission, the competitive bidding option under this division may be used as the market-based standard offer required by division (A) of this section. The commission may determine at any time that a competitive bidding process is not required, if other means to accomplish generally the same option for customers is readily available in the market and a reasonable means for customer participation is developed.

(C) After the market development period, the failure of a supplier to provide retail electric generation service to customers within the certified territory of the electric distribution utility shall result in the supplier's customers, after reasonable notice, defaulting to the utility's standard service offer filed under division (A) of this section until the customer chooses an alternative supplier. A supplier is deemed under this division to have failed to provide such service if the commission finds, after reasonable notice and opportunity for hearing, that any of the following conditions are met:

(1) The supplier has defaulted on its contracts with customers, is in receivership, or has filed for bankruptcy.

(2) The supplier is no longer capable of providing the service.

(3) The supplier is unable to provide delivery to transmission or distribution facilities for such period of time as may be reasonably specified by commission rule adopted under division (A) of section 4928.06 of the Revised Code.

(4) The supplier's certification has been suspended, conditionally rescinded, or rescinded under division (D) of section 4928.08 of the Revised Code.

4928.17 Corporate separation plans.

(A) Except as otherwise provided in sections 4928.31 to 4928.40 of the Revised Code and beginning on the starting date of competitive retail electric service, no electric utility shall engage in this state, either directly or through an affiliate, in the businesses of supplying a noncompetitive retail electric service and supplying a competitive retail electric service, or in the businesses of supplying a noncompetitive retail electric service and supplying a product or service other than retail electric service, unless the utility implements and operates under a corporate separation plan that is approved by the public utilities commission under this section, is consistent with the policy specified in section 4928.02 of the Revised Code, and achieves all of the following:

(1) The plan provides, at minimum, for the provision of the competitive retail electric service or the nonelectric product or service through a fully separated affiliate of the utility, and the plan includes separate accounting requirements, the code of conduct as ordered by the commission pursuant to a rule it shall adopt under division (A) of section 4928.06 of the Revised Code, and such other measures as are necessary to effectuate the policy specified in section 4928.02 of the Revised Code.

(2) The plan satisfies the public interest in preventing unfair competitive advantage and preventing the abuse of market power.

(3) The plan is sufficient to ensure that the utility will not extend any undue preference or advantage to any affiliate, division, or part of its own business engaged in the business of supplying the competitive retail electric service or nonelectric product or service, including, but not limited to, utility resources such as trucks, tools, office equipment, office space, supplies, customer and marketing information, advertising, billing and mailing systems, personnel, and training, without compensation based upon fully loaded embedded costs charged to the affiliate; and to ensure that any such affiliate, division, or part will not receive undue preference or advantage from any affiliate, division, or part of the business engaged in business of supplying the noncompetitive retail electric service. No such utility, affiliate, division, or part shall extend such undue preference. Notwithstanding any other division of this section, a utility's obligation under division (A)(3) of this section shall be effective January 1, 2000.

(B) The commission may approve, modify and approve, or disapprove a corporate separation plan filed with the commission under division (A) of this section. As part of the code of conduct required under division (A)(1) of this section, the commission shall adopt rules pursuant to division (A) of section 4928.06 of the Revised Code regarding corporate separation and procedures for plan filing and approval. The rules shall include limitations on affiliate practices solely for the purpose of maintaining a separation of the affiliate's business from the business of the utility to prevent unfair competitive advantage by virtue of that relationship. The rules also shall include an opportunity for any person having a real and substantial interest in the corporate separation plan to file specific objections to the plan and propose specific responses to issues raised in the objections, which objections and responses the commission shall address in its final order. Prior to commission approval of the plan, the commission shall afford a hearing upon those aspects of the plan that the commission determines reasonably require a hearing. The commission may reject and require refiling of a substantially inadequate plan under this section.

(C) The commission shall issue an order approving or modifying and approving a corporate separation plan under this section, to be effective on the date specified in the order, only upon findings that the plan reasonably complies with the requirements of division (A) of this section and will provide for ongoing compliance with the policy specified in section 4928.02 of the Revised Code. However, for good cause shown, the commission may issue an order approving or modifying and approving a corporate separation plan under this section that does not comply with division (A)(1) of this section but complies with such functional separation requirements as the commission authorizes to apply for an interim period prescribed in the order, upon a finding that such alternative plan will provide for ongoing compliance with the policy specified in section 4928.02 of the Revised Code.

(D) Any party may seek an amendment to a corporate separation plan approved under this section, and the commission, pursuant to a request from any party or on its own initiative, may order as it considers necessary the filing of an amended corporate separation plan to reflect changed circumstances.

(E) Notwithstanding section 4905.20, 4905.21, 4905.46, or 4905.48 of the Revised Code, an electric utility may divest itself of any generating asset at any time without commission approval, subject to the provisions of Title XLIX [49] of the Revised Code relating to the transfer of transmission, distribution, or ancillary service provided by such generating asset.